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CONCEPTUAL DESIGN AND COST STUDY

SULFUR OXIDE REMOVAL FROM POWER PLANT STACK GAS. MAGNESIA SCRUBBING, REGENERATION: PRODUCTION OF CONCENTRATED SULFURIC ACID

TENNESSEE VALLEY AUTHORITY

PREPARED FOR
ENVIRONMENTAL PROTECTION AGENCY

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ERRATA

p. 5 - The first entry in table S-2 should read "Base case--coal-fired units"

p. 24 - The photograph on p. 24 should be on p. 25, and vice versa

p. 37 - The equation referred to near the bottom of the first column and at the top of the second column should be number 27 (not 28)

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The report is a conceptual design and cost study on magnesia scrubbing-regeneration. It describes the process history, current development status, and variations which have been pursued, and presents process chemistry, kinetics, and mass transfer data. It outlines the four leading processing techniques for evaluation, and discusses the advantages and weaknesses of magnesia scrubbing-regeneration as compared to other SO2 removal processes. It gives results of a complete economic evaluation, including details of the capital, annual operating, and lifetime operating cost estimates. It compares magnesia processes with both low (rural) and high (metropolitan) cost limestone scrubbing systems, and gives sensitivities of such variables as unit size, status (new or existing), fuel type, sulfur content of fuel, on-stream time, and net sales revenue. It enumerates conclusions of the study.

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SULFUR OXIDE REMOVAL FROM POWER PLANT STACK GAS

Magnesia Scrubbing - Regeneration: Production of Concentrated Sulfuric Acid

by

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J.P. Simpson, and J.F. Phillips, Jr.

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Muscle Shoals, Alabama 35660
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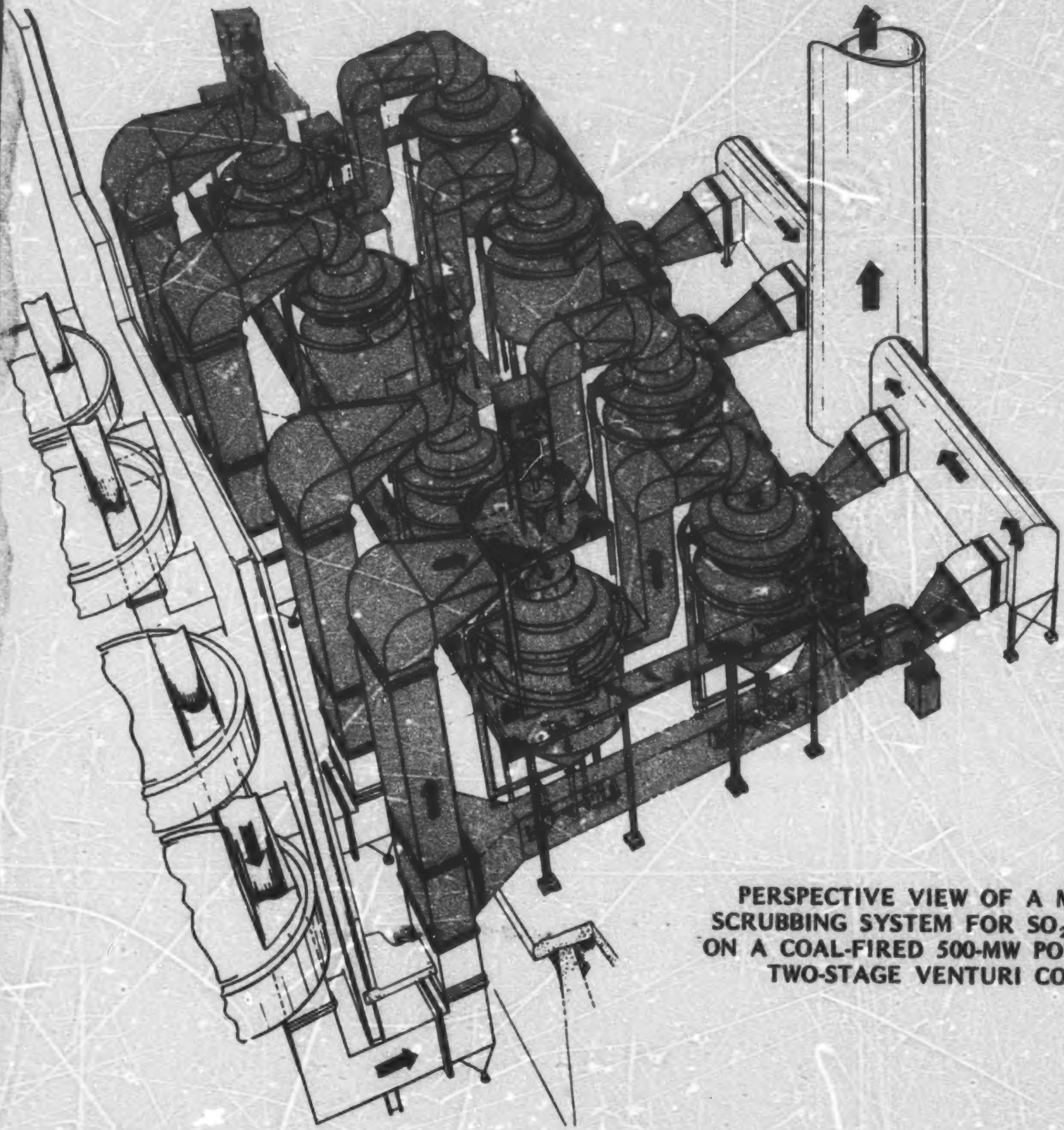

PERSPECTIVE VIEW OF A MAGNESIA SCRUBBING SYSTEM FOR SO_2 REMOVAL ON A COAL-FIRED 500-MW POWER UNIT—TWO-STAGE VENTURI CONCEPT

PREFACE

On February 16, 1967, the National Center for Air Pollution Control, Public Health Service, U. S. Department of Health, Education, and Welfare [now the Office of Research and Monitoring (ORM), Environmental Protection Agency (EPA)] entered into a contract with the Tennessee Valley Authority (TVA) for a series of conceptual design and economic studies to be carried out by TVA on processes for reduction of sulfur oxide and nitrogen oxide emissions from power generation. The purpose is to evaluate objectively and realistically the merits of different methods under consideration for stack gas control, with a common and uniform basis for comparison.

Various types of activities enter into the studies, including:

1. Analysis of the published literature bearing on the processes.
2. Direct contacts to obtain information from organizations currently working on the processes.
3. Bench- and pilot-scale tests to fill in gaps in the information.
4. Specific studies by specialists in power plant design, power plant operation, and air and water pollution to supplement the main study.
5. Preparation of conceptual flowsheets and equipment arrangement drawings for each process.
6. Market appraisals for processes involving recovery of a salable product.
7. Quotations from vendors and fabricators of major pieces of equipment.
8. Examinations of raw material and shipping costs.
9. Order of magnitude cost estimates to cover a wide range of the parameters involved.

Detailed evaluations of the first three studies have been published and can be obtained from:

National Technical Information Service
5285 Port Royal Road
Springfield, Virginia 22151

The reports are identified and priced as shown in the following table:

Title	Number	Price	Year of issue
Sulfur oxide removal from power plant stack gas-sorption by limestone or lime (dry process)	PB 178-972	$3.00	1968
Sulfur oxide removal from power plant stack gas-use of limestone in wet-scrubbing process	PB 183-908	3.00	1969
Sulfur oxide removal from power plant stack gas-ammonia scrubbing: production of ammonium sulfate and use as intermediate in phosphate fertilizer manufacture	PB 196-804	6.00	1970

The present report on magnesia scrubbing-regeneration is concerned primarily with aqueous magnesia scrubbing of power plant stack gas to form magnesium sulfite, drying of sulfite crystals and regeneration of absorbent magnesium oxide for recycle, and production of concentrated sulfuric acid. Also given cursory examination are NO_x removal and production of sulfur.

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A major part of the evaluation has been the analysis of findings by other organizations who have worked on magnesia scrubbing-regeneration. These findings are, of course, the basis for the conceptual design and are referenced in the annotated bibliography. In addition to referenced literature, several organizations have supplied information directly for use in the study; the contributions of the following are acknowledged:

Process Design

Babcock and Wilcox Company
Power Generation Division
Barberton, Ohio 44203

Chemico/Basic
Chemical Construction Corporation
320 Park Avenue
New York, New York 10022

Grillo-Werke Aktiengesellschaft
Weseler Strasse 1
41 Duisburg-Hamborn
GERMANY

Raw Materials—Magnesium Compounds

Basic Chemicals
845 Hanna Building
Cleveland, Ohio 44115

Diamond Shamrock Chemical Company
Chemetals Division
711 Pittman Road
Baltimore, Maryland 21226

Dow Chemical Company
Midland, Michigan 48640

Michigan Chemical Corporation
351 East Ohio Street
Chicago, Illinois 60611

Scrubbers

Air Correction Division
Universal Oil Products Company
Darion, Connecticut 06820

American Air Filter Company, Inc.
215 Central Avenue
Louisville, Kentucky 40208

Babcock and Wilcox Company
Power Generation Division
Barberton, Ohio 44203

Chemico
Chemical Construction Corporation
320 Park Avenue
New York, New York 10022

Heil Process Equipment Corporation
12901 Elmwood Avenue
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MikroPul
Division of the Slick Corporation
10 Chatham Road
Summit, New Jersey 07901

Peabody Engineering
Environmental & Process Div.
39 Maple Tree Avenue
Stamford, Connecticut 06906

Poly Con Corporation
185 Arch Street
Ramsey, New Jersey 07446

Stebbins Linings, Inc.
Stebbins Engineering and Manufacturing Co.
P. O. Box 171
Watertown, New York 13601

Reheaters

Brown Fintube Co.–Therm-Mech. Inc.
P. O. Drawer 52599
Atlanta, Georgia 30305

North American Manufacturing Co.
4457 E. 71st
Cleveland, Ohio 44105

Peabody Engineering Corporation
39 Maple Tree Avenue
Stamford, Connecticut 06906

Sasakura Engineering Co., Ltd.
302 Park St.
Ridley Park, Pennsylvania 19078

Fans

American Standard
Industrial Products Division
165 W. Wieuca Road, N.E.
Atlanta, Georgia 30342

Dewatering Equipment

Ametek/Process Equipment
East Moline, Illinois 61244

Bird Machine Company
South Walpole, Massachusetts 02071

The De Laval Separator Company
Poughkeepsie, New York 12602

Dorr-Oliver, Incorporated
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Pennwalt Corporation
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Straight Line Filters, Inc.
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Wilmington, Delaware 19899

Dryers and Calciners

Bartlett-Snow
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Bethlehem Corporation
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Bethlehem, Pennsylvania 18016

Dorr-Oliver, Incorporated
Stamford, Connecticut 06904

Fuller Company
General American Transportation Corporation
124 Bridge St.
Catasauqua, Pennsylvania 18032

Jeffrey Manufacturing Co.
Division of Jeffrey Galion
P. O. Box 1879
Columbus, Ohio 43216

Nichols Engineering and Research
Corporation
150 William Street
New York, New York 10038

Dust Collectors

American Standard, Inc.
Industrial Products Division
Detroit, Michigan 48232

Dustex Division
American Precision Industries, Inc.
2777 Walden Avenue
Buffalo, New York 14225

Western Precipitation Division
Joy Manufacturing Company
3445 Peachtree Rd., N.E.
Suite 1090
Atlanta, Georgia 30326

Sulfuric Acid Plants

Chemico
Chemical Construction Corporation
320 Park Avenue
New York, New York 10022

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77 Havemeyer Lane
Stamford, Connecticut 06904

Monsanto Enviro-Chem Systems, Inc.
10 South Riverside Plaza
Chicago, Illinois 60606

Newton Chambers Engineering Limited
Thorncliffe, Sheffield S30 4YP
ENGLAND

The Ralph M. Parsons Company
617 West Seventh Street
Los Angeles, California 90017

E. I. du Pont De Nemours & Co., Inc.
Heat Transfer Products Division
Dupont Building
Wilmington, Delaware 19898 (Acid coolers)

CONTENTS

SUMMARY 1
- Study Assumptions 2
- Process Equipment 2
- Investment Requirements 3
- Evaluation Considerations 3
- Comparison and Profitability 4
- Conclusions 7

INTRODUCTION 8

HISTORY AND STATUS 10

PROCESS VARIATIONS 15
- The Magnesia Slurry Process 15
- The Grillo Variation 15
- The Clear Liquor Process 16
- The Showa Denko Process 17
- NO_x Removal Process 17
- Direct Sulfur Production in the Calciner 18

PROCESS CHEMISTRY, PROPERTIES AND KINETICS 20
- Physcial Properties of Process Compounds and Solutions 20
- Solubility of Magnesium Sulfate and Magnesium Sulfite 20
- Optical Properties and Specific Gravity of Solid Materials 22
- Density and Viscosity of Magnesium Sulfite–Magnesium Bisulfite–Magnesium Sulfate Solutions 26
- Vapor Pressure of Sulfur Dioxide Over $MgSO_3$–$Mg(HSO_3)_2$–$MgSO_4$ 26
- Chemistry 26
- Kinetics and Mass Transfer 37
- Formation of Crystalline Deposits (Scaling) 39
- Process Contaminants 40
- Nitrogen Oxide Emission Control 43
- Recovery As Sulfur 46

STUDY ASSUMPTIONS AND DESIGN CRITERIA 50
- Fuels 50
- Flue Gas Composition 51
- Emission Standards 51
- Plant Location 51
- Plant Size and Status 51
- Plant Life, Operating Time, and Capacity Factor 52
- Flue Gas and Sulfur Dioxide Rates 53
- Degree of Sulfur Dioxide Removal 53
- Stack Gas Reheat 53
- Dust Removal 54
- Amount of Storage 55
- Base Case 55
- Process Flowsheets 55
- Solid Waste Disposal 55
- Miscellaneous 55

EQUIPMENT SELECTION AND DESCRIPTION 57
- Scrubbing Alternatives 57
- Slurry or Solution Processing 64
- Sulfite Drying–Calcining 67
- Sulfuric Acid Production 72
- Materials of Construction 73
- Equipment Description 74

INVESTMENT AND OPERATING COST 79
- Fixed Investment 79
- Working Capital 81
- Operating Costs 82
- Results 86

PROFITABILITY AND ECONOMIC POTENTIAL 100
- Marketing 100
- Regulated Economic Evaluation 106
- Nonregulated Economic Evaluation 110
- Cooperative Economics–Central Processing Concept 112

RESEARCH AND DEVELOPMENT NEEDED 131

CONCLUSIONS AND RECOMMENDATIONS 133

REFERENCES AND ABSTRACTS 138

APPENDIX A 147

APPENDIX B 352

TABLES

Page

S-1 Capital requirements for magnesia Scheme A and limestone-wet scrubbing . . . 3
S-2 Cost of magnesia Scheme A vs limestone-wet scrubbing under regulated economics . . . 5
S-3 Profitability of Scheme A with supplementary income as payment for pollution abatement . . . 6
S-4 Profitability of central regeneration-acid manufacturing unit under cooperative economics.[a] Magnesium sulfite supplied from combinations of new 200-, 500-, or 1,000-mw units burning coal with 3.5% sulfur. Regulated magnesia scrubbing cost equalized to high and low projected limestone-wet scrubbing process costs . . . 6
1 Viscosity and density of magnesium sulfite-bisulfite-sulfate solutions . . . 27
2 Variation of slurry/solution viscosity ratio with solid/liquid ratio . . . 26
3 Log_{10} equilibrium constants vs temperature . . . 34
4 Typical limits of ash analysis of United States bituminous coals . . . 41
5 Makeup water analysis . . . 41
6 Analysis of ash pond water . . . 41
7 Impurities of magnesium oxide . . . 42
8 Concentration and impurity input of makeup water . . . 42
9 Equilibrium concentration of NO_x in air and in a typical flue gas at 1 atm . . . 45
10 Effect of total pressure on gas phase composition . 49
11 Estimated flue gas compositions for coal-fired boilers at various nitrogen oxide and sulfur levels, percent by volume . . . 52
12 Estimated flue gas compositions for oil-fired boilers at various nitrogen oxide and sulfur levels, percent by volume . . . 52
13 Emission standards for new steam generating facilities . . . 53
14 Power unit input heat requirements . . . 53
15 Assumed power plant capacity schedule . . . 53
16 Flue gas and sulfur dioxide emission rates . . . 54
17 Required SO_2 removal efficiencies . . . 54
18 Typical ash composition of a western Kentucky coal . . . 57
19 Particle size distribution of fly ash . . . 57
20 Absorption efficiencies attainable with clear liquor scrubbing scheme . . . 61
21 Flue gas temperature . . . 63
22 Assumed pressure drop through gas system in H_2O . . . 64
23 Introduction rate of soluble contaminants into sulfur dioxide absorber . . . 65
24 Introduction rate of fly ash into sulfur dioxide absorber . . . 65
25 Heat requirements of alternative dewatering-drying processes . . . 65
26 Solid-liquid separation alternatives . . . 65
27 Approximate equipment investment requirements for thickening, $ . . . 66
28 Comparison of various $MgSO_3 \cdot 6H_2O$ dewatering alternatives . . . 67
29 Comparison of $MgSO_3 \cdot 6H_2O$ and $MgSO_3 \cdot 3H_2O$ dewatering processes . . . 67
30 Dryer-calciner equipment alternatives . . . 68
31 Estimated investment and operating costs for rotary and fluid bed dryers and calciners for base case installation . . . 71
32 Estimated investment and operating costs for control of dust emissions from the dryer for base case installation . . . 71
33 Estimated composition of feed gas to sulfuric acid unit . . . 72
34 Estimated fixed investment and operating costs for "wet" and "dry" sulfuric acid units for base case installation . . . 73
35 Environmental Protection Agency emission standards for sulfuric acid plants . . . 73
36 Gas flow rates through each scrubbing train, new 500-mw coal-fired units . . . 75
37 Scrubber design conditions . . . 75
38 Design temperature profile for indirect steam reheater system . . . 76
39 Approximate dimensions of rotary dryers and calciners . . . 76
40 Case combinations for coal- and oil-fired units . . 80
41 Indirect cost factors . . . 82
42 Costs for various magnesium oxide-containing raw materials . . . 82
43 Rail shipping costs for magnesium sulfate . . . 83
44 Rail shipping costs for magnesium oxide . . . 83

45 Trucking costs for magnesium sulfate or magnesium oxide . . . 84
46 Estimated overall maintenance costs . . . 85
47 Annual capital charges for power industry financing (new power unit with 30-yr life) . . . 86
48 Total fixed investment requirements—magnesia scrubbing and limestone-wet scrubbing processes[a] . . . 88
49 Process equipment and installation analysis-direct cost for Scheme A[a] (thousands of dollars) . . . 89
50 Process equipment and installation analysis[a] direct cost for limestone-wet scrubbing process (thousands of dollars) . . . 90
51 Possible reduction in investment requirements for magnesia Scheme A—special design provisions . . . 91
52 Comparison of investment requirements for a magnesia system including a new sulfuric acid unit with a system using an existing acid unit . . . 91
53 Total fixed investment requirements Scheme D—central process concept . . . 92
54 Scheme D unit combinations: rated acid production capacity . . . 92
55 Comparison of Scheme A total investment with Scheme D total investment for similar capacity installations . . . 92
56 Average operating costs for magnesia scrubbing processes compared to limestone-wet scrubbing process under regulated economics[a] . . . 93
57 Annual operating costs for magnesia scrubbing processes under nonregulated economics[a] . . . 97
58 Lifetime operating costs[a] for magnesia scrubbing processes (new plants) . . . 98
59 Total operating costs for Scheme D[a] . . . 99
60 Total annual operating cost: combinations of power unit systems in Scheme D . . . 99
61 Summary of U.S. sulfuric acid production—1972 . . . 100
62 Sulfuric acid plant capacity—short tons per day . . . 101
63 Sulfuric acid end-use pattern—1970 . . . 101
64 Typical sulfuric acid strengths and major end uses . . . 105
65 Consumption of phosphate fertilizers in the midwestern states . . . 105
66 Sulfuric acid shipping costs . . . 106
67 Actual and discounted cumulative total and unit increase (decrease) in the cost of power for magnesia schemes and limestone-wet scrubbing process under regulated economics . . . 108
68 Comparison of present worth of cumulative total and unit increase (decrease) in cost of power for case variations of magnesia Scheme A and limestone-wet scrubbing processes under regulated economics . . . 110
69 Required unit sales revenue for sulfuric acid to equalize magnesia and limestone scrubbing process costs . . . 111
70 Economic potential of magnesia scrubbing-regeneration schemes under nonregulated economics . . . 115
71 Profitability of central regeneration-acid manufacturing unit under cooperative economics. Magnesium sulfite supplied from combinations of new 200-, 500-, and 1,000-mw units burning coal with 3.5% sulfur. Regulated stack gas scrubbing costs equivalent to limestone-wet scrubbing process with low limestone cost, on-site solids disposal . . . 123
72 Profitability of central regeneration-acid manufacturing unit under cooperative economics. Magnesium sulfite supplied from combinations of new 200-, 500-, and 1,000-mw units burning coal with 3.5% sulfur. Regulated stack gas scrubbing costs equivalent to limestone-wet scrubbing process with high limestone cost, off-site solids disposal . . . 123

FIGURES

Page
1 Magnesium bisulfite pulping process with chemical recovery . . . 10
2 Magnesia slurry scrubbing-regenerating process as developed by NIIOGAZ (Russian) . . . 11
3 Magnesia-manganese dioxide slurry scurbbing-regeneration process as developed by Grillo-Werke AG . . . 12
4 150-mw prototype MgO-SO_2, recovery scrubbing system at Boston Edison Co.–Mystic No. 6, Boston, Mass. . . . 14
5 Magnesia slurry scrubbing-regeneration process as developed by Chemico-Basic . . . 16
6 Clear liquor variation of magnesia scrubbing-regeneration process . . . 17
7 Showa Denko dry MgO process for SO_2 removal . . . 18
8 Magnesia process for removal of both sulfur and nitrogen oxides from stack gas . . . 19
9 Effect of temperature on magnesium sulfate solubility . . . 21
10 Effect of temperature on magnesium sulfite solubility . . . 21
11 Effect of magnesium sulfate on magnesium sulfite solubility . . . 22
12 Photomicrograph of magnesium sulfite hexahydrate–200 X . . . 23
13 Photomicrograph of magnesium sulfite trihydrate–2000 X . . . 24
14 Photomicrograph of magnesium sulfite trihydrate–200 X . . . 25
15 Effect of $MgSO_4$ and pH on sulfur dioxide vapor pressure over magnesium sulfite slurry . . . 28
16 Effect of dissolved $MgSO_3$ on SO_2 vapor pressure over $MgSO_3$-$Mg(HSO_3)_2$ solutions total SO_2 4.44% . . . 28
17 Effect of dissolved $MgSO_3$ on SO_2 vapor pressure over $MgSO_3$-$Mg(HSO_3)_2$ solutions total SO_2 6.16% . . . 28
18 Effect of $MgSO_4$ content and $Mg(HSO_3)_2$/$MgSO_3$ ratio on solution pH . . . 29
19 Effect of salt concentration on oxygen absorption . . . 31
20 Effect of pH on air oxidation rate in magnesium sulfite-bisulfite solution . . . 31

Page
21 Effect of pH on calcium sulfite oxidation rate . . . 32
22 Effect of p-phenylenediamine and time on oxidation of magnesium sulfite crystals exposed to atmosphere . . . 32
23 Effect of temperature and slurry concentration on conversion rate of $MgSO_3 \cdot 6H_2O$ to $MgSO_3 \cdot 3H_2O$ . . . 32
24 Differential thermogram of $MgSO_3 \cdot 6H_2O$ and $MgSO_3 \cdot 3H_2O$ samples . . . 33
25 Effects of temperature on nature of $MgSO_3$ decomposition products–one hour heating period . . . 33
26 Effect of temperature on nature of $MgSO_3$ decomposition products–15 minutes heating period . . . 35
27 Effect of time and temperature on decomposition of $MgSO_3$ . . . 35
28 Equilibrium constants for combustion reactions . . . 36
29 Equilibrium constants for reactions of magnesium compounds . . . 36
30 Effect of calcination temperature and atmosphere on formation of product materials . . . 36
31 Effect of calcination temperature and atmosphere on formation of product materials (expanded vertical scale) . . . 37
32 Effect of manganese on the rate of magnesium sulfate decomposition . . . 38
33 Effect of gas velocity on mass transfer coefficient . . . 38
34 Effect of liquid mass rate on mass transfer coefficient . . . 39
35 Effect of gas mass flow rate on mass transfer coefficient . . . 39
36 Effect of temperature on mass transfer coefficient in absorption of SO_2 by various solutions . . . 39
37 Effect of time on increase of salt concentration in sulfur dioxide scrubbing system at pH 5.5-6.0 . . . 42
38 Effect of temperature on equilibrium concentrations of NO and NO_2 in combustion gases . . . 43

39 Effect of temperature on equilibrium concentrations of NO for combustion of methane 44
40 Effects of air concentration on NO_x equilibrium in methane–air flames 44
41 $Mg(OH)_2$ scrubbing process 45
42 Effect of C/O atom ratio on gas composition for the system C-O-S at 600° K and one atmosphere total pressure 47
43 Effect of temperature on elemental sulfur recovery in the system C-O-S at P = 1 atm, S/O = 0.5 and C/O = 0.5 (composition for optimum production of sulfur) 47
44 Effect of pressure drop on particulate collection efficiency for a venturi scrubber 58
45 Effect of liquid to gas irrigation ratio on sulfur dioxide absorption efficiency for a mobile bed absorber 59
46 Effect of liquid to gas irrigation ratio on sulfur dioxide absorption efficiency for a venturi absorber 59
47 Effect of liquid to gas irrigation ratio on sulfur dioxide absorption efficiency for a spray absorber 60
48 Effect of liquid to gas irrigation ratio on pressure drop for a mobile bed absorber 60
49 Effect of pressure drop on sulfur dioxide absorption efficiency for a venturi absorber 60
50 Effect of slurry pH on sulfur dioxide absorption efficiency for a mobile bed absorber 60
51 Effect of slurry pH on sulfur dioxide absorption efficiency for a venturi absorber 61
52 Effect of slurry pH on sulfur dioxide absorption efficiency for a spray absorber 61
53 Effect of time on solution-slurry interface position for crystalline $MgSO_3 \cdot 6H_2O$ settling through saturated $MgSO_3 \cdot 6H_2O$ solutions containing soluble $MgSO_4$ 66
54 Effect of moisture content of feed to calciner on composition of calciner offgas 69
55 Effect of moisture content of feed to calciner on concentration of H_2SO_4 69
56 Effect of inlet solids temperature to calciner on composition of SO_2 in calciner offgas 70
57 Effect of feed temperature of solids to calciner on H_2O requirement at H_2SO_4 unit 70
58 Effect of variation in solids disposal cost on annual limestone-wet scrubbing operating cost 81
59 Effect of raw materials limestone cost on annual limestone-wet scrubbing operating cost 84
60 Effect of power unit size on magnesia process investment: new coal-fired units 87
61 Effect of power unit size on magnesia process investment: new oil-fired units 87
62 Effect of plant status (new vs existing) on investment for magnesia Scheme A: coal-fired power units 87
63 Effect of power unit fuel type on investment 87
64 Effect of plant status (new vs existing) on investment for magnesia Scheme A: oil-fired power units 87
65 Effect of sulfur content of coal on investment: 500-mw units 87
66 Effect of sulfur content of oil on investment: 500-mw units 88
67 Effect of plant size and sulfur content of oil on investment 88
68 Effect of power unit size on total fixed investment for Scheme D vs Scheme A 90
69 Effect of total system size on fixed investment: central regeneration concept 90
70 Effect of power unit size on annual operating cost: new coal-fired units under nonregulated economics 94
71 Effect of plant status (new vs existing) on annual operating cost: coal-fired units under regulated economics 94
72 Effect of plant status (new vs existing) on annual operating cost: oil-fired units under regulated economics 94
73 Effect of power unit size on annual operating costs: regulated economics 94
74 Effect of power unit size on unit operating cost: coal-fired units under regulated economics 94
75 Effect of power unit size on unit operating cost: oil-fired units under regulated economics 94
76 Effect of power unit size on unit operating cost of acid: coal-fired units under nonregulated economics 95
77 Effect of sulfur content of coal on annual operating cost under regulated economics 95
78 Effect of sulfur content of coal on unit operating cost of acid under nonregulated economics 95

79 Effect of sulfur content of oil on total annual operating costs under regulated economics 95
80 Effect of annual operating time on annual operating cost under regulated economics 95
81 Effect of annual operating time on annual operating cost under nonregulated economics 95
82 Effect of annual operating time on unit operating cost of acid under nonregulated economics 96
83 Central regeneration system: effect of total system size on annual operating cost under cooperative economics 96
84 Central regeneration system: effect of total system size on unit operating cost under cooperative economics 96
85 Effect of shipping distance on total annual operating cost for Scheme D under cooperative economics 96
86 Effect of shipping distance on unit cost of acid for combinations of Scheme D scrubbing and regeneration plants under cooperative economics 97
87 Sulfuric acid manufacturing capacity 102
88 Location of major coal- and oil-fired power units—1971 104
89 Effect of power unit size on cumulative present worth of total net increase or decrease in the cost of power to consumers for coal-fired power units using magnesia schemes 109
90 Effect of power unit size on cumulative present worth of unit increase or decrease in the cost of power to consumers for coal-fired power units using magnesia schemes . . . 109
91 The effect of power unit size on cumulative present worth of total net increase or decrease in the cost of power to consumers for oil-fired power units using magnesia schemes 112
92 Effect of sulfur content of coal on cumulative present worth of total net increase or decrease in the cost of power to consumers for magnesia Scheme A 113
93 Effect of sulfur content of oil on cumulative present worth of total net increase or decrease in cost of power to consumers for magnesia Scheme A 113
94 Effect of constant onstream time of 7,000 hr/yr on cumulative present worth of total net increase or decrease in cost of power to consumers for coal-fired units using magnesia Scheme A . . . 114
95 Effect of constant onstream time of 7,000 hr/yr on cumulative present worth of unit increase or decrease in cost of power to consumers for coal-fired units using magnesia Scheme A . . . 114
96 Effect of plant age or status on cumulative present worth of unit increase or decrease in the cost of power to consumers for coal-fired plants using magnesia Scheme A 116
97 Effect of fixed investment on cumulative present worth of total net increase or decrease in the cost of power to consumers for coal-fired units using magnesia Scheme A 117
98 Effect of fixed investment on cumulative present worth of total net increase or decrease in cost of power to consumers for oil-fired units using magnesia Scheme A 117
99 The effect of variation in net sales revenue on cumulative present worth of total net increase or decrease in the cost of power to consumers for coal-fired units using magnesia Scheme A . 118
100 Effect of variation in net sales revenue on cumulative present worth of unit increase or decrease in cost of power to consumers for coal-fired plants using magnesia Scheme A 118
101 Effect of annual labor cost variation on cumulative present worth of total increase or decrease in cost of power to consumers for coal-fired units using magnesia Scheme A 119
102 The effect of power unit size on payout period for magnesia Scheme A on coal-fired units 120
103 The effect of power unit size on payout period for magnesia Scheme B on coal-fired units 120
104 The effect of power unit size on payout period for magnesia Scheme C on coal-fired units 120
105 The effect of power unit size on interest rate of return for magnesia Scheme A on coal-fired units 120
106 The effect of power unit size on interest rate of return for magnesia Scheme B on coal-fired units 120
107 The effect of power unit size on interest rate of return for magnesia Scheme C on coal-fired units 120
108 The effect of power unit size on payout period for magnesia Scheme A on oil-fired units 121
109 The effect of power unit size on payout period for magnesia Scheme B on oil-fired units 121
110 The effect of power unit size on interest

rate of return for magnesia Scheme A on oil-fired units 121
111 The effect of power unit size on interest rate of return on magnesia Scheme B on oil-fired units 121
112 The effect of sulfur content of coal on payout period for magnesia Scheme A on coal-fired units 121
113 The effect of sulfur content of coal on interest rate of return for magnesia Scheme A on coal-fired units 121
114 The effect of sulfur content of oil on payout period for magnesia Scheme A on oil-fired units 122
115 The effect of sulfur content of oil on interest rate of return for magnesia Scheme A on oil-fired units 122
116 The effect of variation in net sales revenue on interest rate of return for magnesia Scheme A on coal-fired units—low payment 124
117 The effect of variation in net sales revenue on interest rate of return for magnesia Scheme A on coal-fired units—high payment 124
118 The effect of variation in net sales revenue on payout period for magnesia Scheme A on coal-fired units—low payment 124
119 The effect of variation in net sales revenue on payout period for magnesia Scheme A on coal-fired units—high payment 124
120 The effect of variation in fixed investment on interest rate of return for magnesia Scheme A on coal-fired units—low payment 124
121 The effect of variation in fixed investment on interest rate of return for magnesia Scheme A on coal-fired units—high payment 124
122 The effect of constant onstream time on payout period for magnesia Scheme A on coal-fired units 125
123 The effect of power unit age or status on interest rate for magnesia Scheme A on coal-fired units 125
124 The effect of annual labor cost escalation on interest rate of return for magnesia Scheme A on coal-fired units 125
125 The effect of annual labor escalation on payout period for magnesia Scheme A on coal-fired units 125
126 The effect of recycle magnesium oxide cost on cumulative present worth of increase or decrease in cost of power to consumers for regulated portion of magnesia Scheme D under cooperative economics 126
127 The relationship of recycle MgO cost on increase in the cost of power to consumers for 200-, 500-, and 1,000-mw scrubbing systems of Scheme D 126
128 The effect of shipping distance for recycle magnesium oxide on cumulative present worth of the increase or decrease in unit cost of power to consumers in the regulated portion of magnesia Scheme D under cooperative economics 127
129 The effect of power unit size on interest rate of return of centralized regeneration-acid plants supplied by combinations of 200-, 500-, and 1,000-mw scrubbing systems under cooperative economics 128
130 The effect of shipping distance on interest rate of return for centralized regeneration-acid units—combinations of 500-mw scrubbing systems, recycle MgO cost—$15/ton 128
131 The effect of shipping distance on interest rate of return for centralized regeneration-acid units—combinations of 500-mw scrubbing systems, recycle MgO cost—$55/ton 128
132 The effect of variation in sales revenue for recycle MgO on interest rate of return of centralized regeneration-acid units—combinations of 200-mw scrubbing systems 128
133 The effect of variation in sales revenue for recycle MgO on interest rate of return of centralized regeneration-acid units—combinations of 500-mw scrubbing systems 129
134 The effect of variation in sales revenue for recycle MgO on interest rate of return for centralized regeneration-acid plants—combination of 1,000-mw scrubbing systems 129
135 The effect of variation in net sales revenue for sulfuric acid on interest rate of return for centralized regeneration-acid units—combinations of 200-mw scrubbing systems—recycle MgO cost—$25/ton 129
136 The effect of variation in net sales revenue for sulfuric acid on interest rate of return for centralized regeneration-acid units—combinations of 200-mw scrubbing systems—recycle MgO cost—$55/ton 129
137 The effect of variation in net sales revenue for sulfuric acid on interest rate of return for centralized regeneration-acid units—combinations of 500-mw scrubbing systems—recycle MgO cost—$15/ton 130
138 The effect of variation in net sales revenue for sulfuric acid on interest rate of return for centralized regeneration-acid units—combinations of 500-mw scrubbing systems—recycle MgO cost—$55/ton 130
139 The effect of variation in net sales revenue for sulfuric acid on interest rate of return for centralized regeneration-acid units—combinations of 1,000-mw scrubbing systems—recycle MgO cost—$10/ton 130
140 The effect of variation in net sales revenue for sulfuric acid on interest rate of return for centralized regeneration-acid units—combinations of 1,000-mw scrubbing systems—recycle MgO cost—$55/ton 130

SUMMARY

The decline in air quality over the past decade has prompted increased efforts by government and industry to reduce objectionable emission from fossil-fueled power plants. With the recently instituted Federal ambient and emission standards plus state and local requirements as guides, several routes to pollution abatement are being investigated. One of the more actively pursued alternatives for reduction of particulate matter, sulfur oxides, and in some cases nitrogen oxides, is stack gas scrubbing processes.

The present report on sulfur oxide removal with aqueous magnesia slurries or solutions is the fourth in a series of conceptual design and cost studies being carried out by the Tennessee Valley Authority (TVA) for the Environmental Protection Agency (EPA). The first two studies were concerned with the use of lime or limestone as absorbents, which convert the gaseous sulfur oxides to solid compounds (calcium sulfite and calcium sulfate) that are discarded. These were called "throwaway" processes. The third study included processes using aqueous ammonia solutions as the scrubbing medium and recovering the sulfur oxides as ammonium sulfites which were converted to sulfate and used as an intermediate in the production of fertilizer products. This was the first recovery system examined in which materials could be produced for sale to offset, at least partially, the cost of operation.

Processes recovering the sulfur oxides in a useful form are potentially superior to the throwaway type because they do not generate solid waste disposal problems and also offer the possibility that sales revenue will reduce the cost of sulfur oxide removal. It should be kept in mind, however, that recovery processes are generally more complex, may be more expensive to install, and require a definite commitment to sell the products produced.

In recent years, numerous processes have been proposed for sulfur oxide recovery and some of these are currently being developed extensively. The purpose of the EPA-TVA conceptual design series is to select the more promising of these and subject each to a detailed study in which the best design is developed from available data; capital and operating costs are estimated on a uniform basis; a market survey is made to estimate sales revenue; total cash flow is related to economic promise; and needed research and development are identified.

Scrubbing with magnesium oxide slurry to form magnesium sulfite, followed by decomposition to produce concentrated SO_2 (MgO is recycled), is one of the more promising processes for sulfur dioxide removal. Slurries of magnesia are good absorbents; however, the most outstanding assets of the concept are:

1. The ease of separation of the sulfite salts formed from the scrubber liquor.
2. The ability to regenerate and recycle the absorbent, magnesium oxide.
3. The avoidance of a solids disposal problem.
4. The capability of separating, both financially and operationally, the power unit scrubbing system from the chemical manufacturing and marketing function.

At the same time, the process does require extra expense for drying and calcining the intermediate $MgSO_3$ and $MgSO_4$ formed, and the apparent need for two scrubbing stages on coal-fired units to avoid mixing fly ash with the undissolved absorbent. As with all aqueous scrubbing processes, stack gas reheating, if required, would also add expense. The potential of the process, however, is outstanding enough to merit demonstration on a 155-mw, oil-fired power unit of Boston Edison. This system, jointly funded by EPA and a large group of chemical companies and utilities, started up in early 1972.

In the regeneration of the absorbent, sulfur dioxide is released at concentrations practical for conversion to sulfuric acid, liquified sulfur dioxide, or elemental sulfur. With the limited market for liquified sulfur dioxide and the higher cost of conversion to sulfur, the product receiving primary attention in this report is sulfuric acid. Commercial grades of acid including 98% concentration and oleum are easily produced in the process.

Around the world, development work on magnesia scrubbing for power plant stack gas has followed at least three major technological routes. The Russians, Japanese, and Americans have concentrated on the use of magnesium sulfite-magnesium oxide slurries having a basic pH; whereas a German company has researched the use of an absorbent activator, manganese dioxide, with the scrubbing slurry. In addition, using technology associated with sulfite pulping practice, at least one American company has also investigated the use of magnesium sulfites in acidic solution so that simultaneous particulate and SO_2 removal can be accomplished with a single scrubber in coal-fired unit applications.

Each of these three scrubbing schemes is given detailed review in the present study and is described as follows:

1. *Scheme A–magnesia slurry variation*–Wet scrubbing with magnesium oxide-magnesium sulfite-water slurry to absorb SO_2 and form undissolved $MgSO_3 \cdot 6H_2O$ plus some $MgSO_3 \cdot 3H_2O$. The $MgSO_3 \cdot 6H_2O$ is thermally converted to trihydrate and dried to form anhydrous $MgSO_3$. This material, along with any sulfate formed by oxidation, is calcined with coke to generate MgO for recycle and SO_2 for production of H_2SO_4 by the contact process.
2. *Scheme B–MgO-MnO$_2$ slurry variation*–Wet scrubbing with magnesium oxide-magnesium sulfite slurry containing a scrubbing reaction activator, manganese dioxide. The sulfites, sulfates, and unreacted manganese dioxide are dried and calcined to regenerate the absorbent and activator with the SO_2 rich gas being processed to H_2SO_4.
3. *Scheme C–clear liquor variation*–Wet scrubbing of stack gas to remove particulates and absorb SO_2 simultaneously with an acidic solution of magnesium sulfites, followed by separation of insoluble fly ash and liquor and addition of MgO to the liquor to precipitate $MgSO_3 \cdot 6H_2O$. The crystals of sulfite are then converted to trihydrate, dried, and calcined. MgO is recycled and SO_2 processed to acid.

The above variations can be applied to multiple power units more economically than with individual power plants by taking advantage of a concept called "central processing." By processing (calcining and acid production) the dried sulfite material from several scrubbing operations in a single, large plant, a more efficient operation (higher annual operating time) can be derived and economy of scale can be achieved. This concept is not a technological variation, but deserves separate consideration (Scheme D) to evaluate the economic merit of the idea which, of course, can be used in other type absorbent processes as well.

Some earlier preliminary investigations (1970) indicate the possible use of a variation in magnesia scrubbing for NO_x control. Recent work (1972), however, indicates that no more than 10% removal can be expected; therefore, magnesia scrubbing should not be counted as a means of meeting new Federal NO_x emission standards.

Study Assumptions

Recovery process economics depend on several factors including power plant size, type of fuel burned, sulfur content of fuel, operating factor, plant location, unit efficiency, and unit status (new vs existing). For detailed design and cost estimating purposes, it is necessary to assume a combination of conditions as a base case for both oil- and coal-fired units. In the economic evaluation, the effect of variations in the major parameters is determined. The basic conditions assumed are as follows:

Power unit size, mw	500
Sulfur content of coal, %	3.5
Sulfur content of oil, %	2.5
Ash content of coal, %	12
Heating value of coal, Btu/lb	12,000
Heating value of oil, Btu/lb	18,500
Boiler excess air and leakage, %	
Coal-fired unit	33
Oil-fired unit	15
Degree of dust removal, %	99
Degree of SO_2 removal, %	
Slurry Schemes A, B, D	90
Solution Scheme C	77
Boiler type	Horizontal, frontal-fired
Plant location	Midwest
Capacity factor, % of nameplate rating	
first to 10th year	80
11th to 15th year	57
16th to 20th year	40
21st to 30th year	17
Avg over life of unit	48.5
Air preheater exhaust temp, °F	310
Stack gas reheat temp, °F	175
Unit heat rate, Btu/kwh	9,000
Product storage, days	30

Process Equipment

The scrubbers, ductwork, and fans are the most expensive items in a recovery process because they must handle the full flow of gas (over 1,000,000 tons/day for a 1000-mw boiler). The slurry processing, drying, calcining and sulfuric acid units handle a lower throughput of material depending on S content of fuel. Stagewise scrubbing will be necessary when using slurry scrubbing on coal-fired units to keep the majority of the fly ash from entering the drying and calcining operations. For particulate removal, a venturi type device using clarified, circulated water is chosen although electrostatic precipitators and bag filters could be used. Electrostatic precipitators have shown variations in outlet loading due to operating characteristics and time, and bag filters are more expensive.

In scrubbing sulfur oxides, slurry systems can utilize venturi, mobile bed (plastic sphere type) or spray units. For solution scrubbing service (Scheme C), plate and packed scrubbers might be added to the list of acceptable devices, but consideration must be given to residual fly ash carryover causing plugging. In any case, corrosion and erosion protection should be provided by linings such as rubber or polyester-fiberglass.

At this time, mist eliminator performance in slurry scrubbing service is of concern with a variety of designs and materials of construction currently in use or under study.

In this study, chevron vane type devices constructed of or coated with corrosion-erosion resistant materials are used.

Reheating can be accomplished by indirect steam heat exchange on new units for which design provisions have been made in the steam cycle; however, since existing units are not likely to have excess steam available, direct fuel oil reheat is preferred. Neither of these methods is the most economical choice available, but the reliability of the indirect liquid-gas heat exchange method considered in previous studies has become suspect.

Solids separation in the slurry processing area probably can be accomplished best by first thickening the 10% solids slurry to 40% and then centrifuging to a cake containing less than 15% free water. Since good test data are not available, separation by filtration can not be ruled out; however, cakes containing less than 15% water may be more difficult to obtain.

Although rotary type devices are being utilized for drying and calcining in the Boston Edison demonstration project, discussions with vendors and some process developers have indicated that possibly greater efficiency and lower cost could be obtained with fluid bed units. In the absence of test data, some doubt remains; however, fluid bed systems appear to be the best choice.

The "dry" gas cleanup system for calciner off-gas and the sulfuric acid plant utilize relatively well established technology; therefore, few unforeseen problems should arise in these areas. If desirable, the magnesia process could easily be added to existing acid units which currently burn elemental sulfur.

Investment Requirements

Investment under various combinations of conditions are given for Scheme A and limestone-wet scrubbing in table S-1. Although Scheme C has the lowest investment requirement ($36.2/kw for base case) for coal-fired power unit scrubbing systems, SO_2 removal for Scheme C may not be sufficient in all cases to meet Federal emission standards for new units. In addition, the data supporting clear liquor scrubbing are limited; therefore, the scheme should not be considered as the leading process. Depending on type and sulfur content of fuel and power unit size and age, the magnesia Scheme A investment ranges from 1-28% higher than the investment for limestone-wet scrubbing.

Evaluation Considerations

Evaluation of recovery processes brings in factors such as product marketability and price, profit margin and taxes, and project financial promise, all of which make the analysis more difficult than for throwaway processes. It would be desirable, of course, that recovery methods show promise of a net profit, but this is not essential because recovery should be preferable to throwaway, even at a net loss, as long as the loss is lower than for throwaway systems. The cost of limestone-wet scrubbing was used as the criterion for comparison. Both high cost ($6/ton limestone, $6/ton solids disposal) and low cost ($2.05/ton limestone, variable on-site solids disposal) limestone

Table S-1. Capital requirements for magnesia Scheme A and limestone-wet scrubbing.

	Capital, $/kw of power generating capacity	
Conditions	Magnesia Scheme A wet scrubbing	Limestone-wet scrubbing
Base case—coal-fired units (500-mw, new power unit, 3.5% S in coal, reheat to 175°F)	43.5	35.2
Exceptions to base case (coal fired)		
Existing power unit	49.3	39.9
2.0% sulfur	37.6	32.3
5.0% sulfur	48.5	37.8
200-mw	58.4	46.0
1,000-mw	33.1	27.4
Base case—oil-fired units (500-mw, new power unit, 2.5% S in oil, reheat to 175°F)	24.9	21.4
Exceptions to base case (oil fired)		
Existing unit	27.8	24.8
1.0% sulfur	19.8	19.0
4.0% sulfur	29.1	23.4
200-mw	33.4	28.5
1,000-mw	18.8	16.6

systems were estimated using the same variables as used for the magnesia schemes.

The basis on which the recovery process is financed is a major consideration in evaluating economic promise and acceptability. If a power company finances the entire project, it can be assumed that the investment would become part of the rate base on which the company is allowed to earn what the regulatory authority regards as a reasonable return on investment. If sulfur oxide removal, either by throwaway or recovery method, were to increase operating cost, then the price of power to consumers presumably could be raised to offset the extra cost. Under such basis, sulfur oxide removal (even by recovery) could be considered as necessary for production of power just as is the boiler operation, dust removal, or cooling water system, and the costs; therefore, passed on to the consumer. It is true that rate increases are often strongly contested and delayed, and that the full adjustment may not always be allowed, so that the power company has the incentive to avoid extra investment and expense. In general, however, the power company has a more or less assured profit. For this reason, there is little risk and capital can be attracted at regulated rates of return.

As a practical matter (but within limits), loss from operation of a sulfur dioxide recovery system could be passed on to the power consumer. The main trouble is the considerable time and effort usually associated with obtaining a rate increase. Another consideration is that neither power producer nor regulatory authority has any reason to favor recovery if it losses more money than alternates such as limestone-wet scrubbing. Since both alternatives have the same rate of return on investment under the regulated financing basis, the present worth of expenditures over the life of the plant must be compared for both the recovery process and the limestone-wet scrubbing process to determine which results in the least cost to the power consumer.

Since power companies generally are not familiar with chemical production and marketing, there would be some advantage if a chemical company built and operated the recovery process for a fee and marketed the products. For a private, nonregulated company to enter into such an activity, however, the project would have to be promising enough to attract the necessary capital from investors. It is difficult to say how much promise is needed because this varies with the situation. It generally is considered that the project cash flow (depreciation plus profit after taxes) should pay out the original investment in about 5 years or, on another basis which takes into account the time value of money, the interest rate of return should be about 15%. For the relatively high investment required by sulfur oxide recovery processes, this is a major hurdle.

A characteristic of the central process concept is that features of both regulated and nonregulated economics can be utilized to advantage. If by cooperative arrangement, magnesia scrubbing and drying operations are placed under power industry (regulated) economics and regeneration and acid manufacture are covered under nonregulated economics, the power company can avoid any responsibility for acid production and marketing and the chemical company can reduce its capital responsibility to levels more likely to achieve successful profitability. By charging the power company for regenerated MgO and also by selling sulfuric acid, enough revenue might be obtained for a chemical company to justify manufacturing acid from magnesium sulfite rather than by the more conventional purchase of elemental sulfur. The revenue obtained for regenerated MgO would, of course, depend on the resultant cost to the power company for magnesia scrubbing as opposed to limestone-wet scrubbing or other feasible alternatives.

Comparison and Profitability

An important consideration for comparison under regulated economics, and in profitability analysis under nonregulated economics, is net sales revenue for the sulfuric acid. A market review for the acid resulted in the following conclusions:

1. The growth rate of sulfuric acid production is about 4-6%/year generally paralleling that of the phosphate fertilizer industry.
2. The best end-use market appears to be the phosphate fertilizer industry as an acidulant for phosphate rock. The product is used in many other applications, however, any of which merit consideration.
3. The most promising locations for magnesia scrubbing regeneration systems appear to be on waterways serving the areas where sulfuric acid is now heavily marketed. Areas on the Ohio and Mississippi Rivers, and along the Gulf and East Coasts are prime spots.
4. Sales price will be based on competition in each individual area plus flexibility of demand. In those areas where byproduct acid or low cost sulfur are available competition will be greatest.
5. Expected net sales revenue after shipping and sales expense are deducted could average about $8.00/ton of 100% acid for single site systems and $12.00/ton for large central processing units. In the best locations these net backs and maybe more should be attainable through the 1970's.
6. Long-term marketing contracts appear to be practical since the likelihood of escalating sales revenue due to prolonged product shortages is not in sight.

Comparison under regulated economics—A comparison of Scheme A with both high and low cost limestone scrubbing is given in table S-2. The values shown are the cumulative present worth of the net annual costs over the

Table S-2. Cost of magnesia Scheme A vs limestone-wet scrubbing under regulated economics.

		Cumulative present worth of net annual costs, $ millions	
		Limestone-wet scrubbing	
Conditions	Scheme A[a]	Low limestone process cost[b]	High limestone process cost[c]
Base case–oil-fired units (500-mw, new unit, 3.5% S in coal, 48.5% average capacity factor over 30 yr, reheat to 175° F)	64.7	55.0	70.3
Exceptions to base case (coal fired)			
Existing unit (27 yr life)	68.7	57.7	71.9
2.0% sulfur	56.4	49.4	59.9
5.0% sulfur	71.8	60.0	80.4
200-mw	36.3	29.3	33.9
1,000-mw	94.9	84.3	117.3
Base case–oil-fired units (500-mw, new unit, 2.5% S in oil, 48.5% average capacity factor over 30 yr, reheat to 175° F)	38.3	34.0	38.6
Exceptions to base case (oil fired)			
Existing unit (27 yr life)	40.2	36.4	40.6
1.0% sulfur	31.1	29.7	30.9
4.0% sulfur	44.2	37.9	46.2
200-mw	21.7	18.6	19.4
1,000-mw	56.6	52.5	63.6

[a] Net sales revenue assumed at $8/ton of acid.
[b] Limestone cost–$2.05/ton; on-site pond disposal of solids.
[c] Limestone cost–$6/ton; off-site solids disposal cost, $6/ton.

life of the power unit; this base is used because under the variety of conditions one system may be better at some yearly levels of operation and vice versa at other levels. Thus, the values represent the total bill in current dollars including return on investment and income taxes for particulate and SO_2 control over the power plant life.

Except for the small 200-mw units, the costs of magnesia Scheme A examples lie between the high and low limestone scrubbing costs. The only magnesia case with costs lower than the low cost limestone system is a 1000-mw, coal-fired unit using Scheme C, the least developed variation. Units smaller than 300-mw would most likely use limestone scrubbing if funding were under regulated economics. Because the incremental cost of producing additional acid exceeds $8/ton (net sales revenue for acid), increasing onstream time and higher sulfur content of fuel does not improve the magnesia process economics.

Profitability under nonregulated economics–Based on projected $8/ton revenue from acid sales alone, all magnesia cases examined have negative interest rates of return and no payout. If additional revenue in the form of a fee equivalent to the cost of limestone-wet scrubbing or other competitive SO_2 control method is charged by the chemical company for sulfur oxide abatement, profitability can be derived. Shown in table S-3 are payout periods in years and interest rates of return in % for Scheme A assuming revenue from both a fee and acid sales.

As would be expected, the results depend on the size of the fee charged; for a fee equivalent to a high-cost limestone scrubbing process, desirable profitability could be achieved in some cases and for a smaller fee equivalent to a low-cost limestone process, low profitability would result in all cases. Funding under this concept will probably be limited.

Profitability of cooperative central process ventures–With the separation of investment and operating responsibility and the advantage of economy of scale for large central acid complexes, cooperative ventures (Scheme D) between power companies and chemical companies are the best route to financial funding of magnesia systems. Given in table S-4 are the payouts and interest rates of return after income taxes for Scheme D systems assuming revenue from both acid and recycle MgO sales. The price of recycle MgO must be such that magnesia scrubbing cost does not exceed that of competitive limestone scrubbing for the same power unit. For a 500-mw, coal-fired unit, only about $15-20/ton could be paid for recycle MgO before exceeding

Table S-3. Profitability of Scheme A with supplementary income as payment for pollution abatement.

Conditions[a]	Low equivalent payment[b]		High equivalent payment[c]	
	Payout, yr	Interest rate of return, %	Payout, yr	Interest rate of return, %
Base case—coal-fired units (500-mw, new unit, 3.5% S in coal, 48.5% average capacity factor over 30 yr, reheat to 175° F)	7.6	8.8	5.6	14.9
Exceptions to base case (coal fired)				
Existing unit (27 yr life)	7.7	8.4	5.7	13.6
2.0% sulfur	7.4	9.5	5.7	14.3
5.0% sulfur	7.7	8.5	5.4	15.7
200-mw	8.3	7.4	6.7	11.0
1,000-mw	7.1	10.0	4.8	18.1
Base case—oil-fired units (500-mw, new unit, 2.5% S in oil, 48.5% average capacity factor over 30 yr, reheat to 175° F)	7.2	9.8	6.1	13.0
Exceptions to base case (oil fired)				
Existing unit (27 yr life)	7.0	10.0	6.0	12.7
1.0% sulfur	6.6	11.5	6.2	12.6
4.0% sulfur	7.5	9.0	5.8	14.0
200-mw	7.6	8.8	7.1	9.9
1,000-mw	6.8	10.9	5.3	15.8

[a] Net sales revenue assumed at $8/ton of acid.
[b] Equivalent to limestone-wet scrubbing cost assuming low limestone price, on-site pond disposal of solids.
[c] Equivalent to limestone-wet scrubbing cost assuming high limestone price, off-site disposal of solids.

Table S-4. Profitability of central regeneration-acid manufacturing unit under cooperative economics.[a] Magnesium sulfite supplied from combinations of new 200-, 500-, or 1,000-mw units burning coal with 3.5% sulfur. Regulated magnesia scrubbing costs equalized to high and low projected limestone-wet scrubbing process costs.

Case units and size	Payout, years		Interest rate of return, %	
	Recycle MgO[b] at $25/ton	Recycle MgO[c] at $55/ton	Recycle MgO[b] at $25/ton	Recycle MgO[c] at $55/ton
200-mw equivalent	None	8.4	Neg.	3.3
5 x 200-mw equivalent	6.6	3.4	8.2	26.6
10 x 200-mw equivalent	5.2	2.7	14.0	35.5
15 x 200-mw equivalent	4.6	2.4	17.2	40.6
	Recycle MgO[b] at $15/ton	Recycle MgO[c] at $55/ton	Recycle MgO[b] at $15/ton	Recycle MgO[c] at $55/ton
500-mw equivalent	None	5.1	Neg.	14.4
2 x 500-mw equivalent	9.9	3.5	0.3	25.3
4 x 500-mw equivalent	7.7	2.8	5.1	34.1
6 x 500-mw equivalent	6.5	2.4	8.7	39.7
	Recycle MgO[b] at $10/ton	Recycle MgO[c] at $55/ton	Recycle MgO[b] at $10/ton	Recycle MgO[c] at $55/ton
1,000-mw equivalent	None	3.6	Neg.	24.4
2 x 1,000-mw equivalent	9.9	2.9	0.1	33.0
3 x 1,000-mw equivalent	8.3	2.5	3.5	38.5

[a] Nonregulated portion of system with 10 yr life; acid revenue—$12/ton.
[b] Equivalent to limestone-wet scrubbing costs assuming low limestone price, on-site pond disposal of solids
[c] Equivalent to limestone-wet scurbbing costs assuming high limestone price, off-site disposal of solids.

the low-cost limestone system; however, approximately \$55/ton could be paid if competition came from a high-cost limestone system.

The results in table S-4 indicate that the smaller the power unit supplying $MgSO_3$ and the larger the acid complex, the better the profitability which could be achieved. A 3000-mw equivalent acid plant supplied by fifteen 200-mw units would show excellent profit making potential—17.2% interest rate of return with \$25/ton for recycle MgO and \$12/ton for sulfuric acid or 40.6% return for \$55/ton recycle MgO and \$12/ton acid.

Conclusions

The more important conclusions derived from this study can be summarized as follows:

1. Sulfur dioxide absorption by magnesia slurry scrubbing is effective and the major portions of the process as conceptualized utilize proven technology.

2. Magnesia scrubbing, like limestone scrubbing, is not an effective means of NO_x removal from power plant stack gas.

3. Magnesia slurry scrubbing-regeneration has been tested in laboratory and pilot plant stages and at least one large scale demonstration is underway.

4. Although limited experience is available to guarantee performance, equipment for commercial systems can be obtained at this time from vendors and fabricators. Depending on fuel type, sulfur content, plant size and age, the magnesia slurry process investment requirements vary from 1 to 28% greater than for limestone-wet scrubbing, another approach to sulfur dioxide removal which does not produce a salable product, but requires disposal of large amounts of waste sludge.

5. For most U. S. fossil-fueled power plants, achievable net sales revenue for recovered 98% sulfuric acid would probably average only \$8-12/ton over the next decade or so; however, there will be applications where better net backs are obtainable. Competition will continue from other sources and grades of byproduct sulfuric acid and virgin acid made from low cost sulfur.

6. Primary economic factors are investment, product volume (depending on power unit size and sulfur content of fuel), net sales revenue (from all sources), competitive cost of alternatives, and basis of financing. Raw material, labor, shipping costs, onstream time, and plant age are significant, but not nearly as important as the primary factors.

7. Under total regulated financing, magnesia systems can compete with limestone scrubbing on larger (400-mw or greater) power units. The limestone process would be favored in rural areas (low cost limestone and space for solids disposal) whereas the magnesia scrubbing-regeneration process would appear desirable in crowded metropolitan areas.

8. Total nonregulated industry financing and operation appear unlikely; however, with a large fee for pollution abatement and large size units, such funding can be considered.

9. A cooperative venture between several power companies and a chemical company, with each supplying capital for and operating their portion of the process, appears to be a good way to fund a magnesia system. It will be necessary for the regeneration-acid plant to charge a service fee for MgO processed from $MgSO_3$ in order to obtain sufficient revenue for desirable profitability.

10. Thus far, interest in the magnesia scrubbing-regeneration process has centered more on replacement of sulfur as raw material in existing sulfuric acid plants with existing markets rather than for added capacity to meet increasing acid markets.

11. There are a limited number of locations that can support a central process installation. The Midwest, along the Ohio and Mississippi Rivers, and the Gulf and East Coasts are prime targets.

12. For short-range shipping distances (0-50 miles), the cost of shipping $MgSO_3$ and MgO between sites is a small part of the total process cost and will not greatly influence process application; however, as distances exceed 100 miles, shipping cost becomes much more significant.

Additional research and development of the process should be performed primarily on the demonstration level to determine effects of process factors such as contamination build-up over long periods of MgO recycle, corrosion-erosion of construction materials, scaling difficulties, and adaptability to power plant operation. Some work on oxidation, crystal growth, effectiveness of additives such as manganese dioxide and the manufacture of sulfur in the calciner should be performed on the bench or pilot levels.

INTRODUCTION

The total emission of sulfur dioxide (SO_2) in the United States during 1970 is estimated to have been about 37 million tons (21) and is expected to increase about 65% during the decade of the 70's. Approximately 55% of the 1970 emissions resulted from combustion of coal and oil at power generating plants, and by 1980 two-thirds of the total emissions are expected to originate from this source as a result of the rapid increase in electrical power demand. The contribution of power plant emissions to the overall condition of air quality has prompted considerable effort toward reducing the SO_2 and particulate concentrations of stack gases.

During the past few years, many Federal, state, and local governments have established both ambient and emission standards in an effort to improve air quality. The need for particulate control generally has been accepted by the utility industry and fly ash control devices have become almost standard equipment on most new power plants; many existing plants are currently being upgraded or retrofitted with improved equipment. Sulfur dioxide is now getting the same attention as particulate matter; however, systems for its control are still undergoing continuing development in demonstration size plants.

There appears to be several promising alternative routes to SO_2 emission control in power generation, including the use of naturally occurring low sulfur fuel, coal and fuel oil desulfurization, alteration of combustion processes, nuclear power, and stack gas removal processes, either recovery or nonrecovery. Each alternative has advantages and disadvantages, and only thorough evaluation by each potential user can indicate which is best. However, there probably will not be one single route which will satisfy all of industry's needs.

With funding provided by the Air Quality Act of 1967 and more recently the Clean Air Act of 1970, the Office of Research and Monitoring of the Environmental Protection Agency (formerly National Air Pollution Control Administration–NAPCA) has become increasingly active in promoting research and development on the various ideas for reducing power plant emissions. In the case of stack gas cleaning processes, literally dozens of concepts have been proposed during recent years. The field became so complicated that several years ago ORM contracted for a series of area surveys to sort out the methods, organize them into manageable classifications, and evaluate them on a screening basis. The processes were classified as follows:

1. Scrubbing with aqueous salts.
2. Sorption by metal oxides.
3. Catalytic oxidation of sulfur dioxide to sulfur trioxide.
4. Sorption by inorganic solids other than oxides.
5. Reduction of sulfur dioxide to sulfur.
6. Sorption by inorganic liquids.
7. Sorption by organic solids.
8. Sorption by organic liquids.
9. Separation by physcial methods.

Of these, the first three have received major attention, and pilot plants and large demonstration scale units funded by EPA and others are under construction or have been built for processes falling within each of the three classes. It is not appropriate here to review these processes; however, it can be said that each has potential which can only be evaluated by detailed analysis.

As part of the ORM-EPA program, the Tennessee Valley Authority has over the last few years been preparing a series of conceptual design and cost studies on several methods of removing sulfur oxides and nitrogen oxides from power plant stack gases. This report on the aqueous magnesia scrubbing-regeneration process is the fourth in the series of EPA-TVA conceptual design and cost studies. The first two reports covered the use of limestone or lime in dry absorption (88) and wet scrubbing processes (89). These processes are considered to be the nonrecovery or "throw-away" type in that the reaction products are waste materials and are discarded. The third study, ammonia scrubbing (production of ammonium sulfate and its use as an intermediate in phosphate fertilizer manufacture) (87), was the first recovery process evaluated and, of course, required a more thorough economic appraisal since a salable product was derived.

The present report on aqueous magnesia scrubbing-regeneration is concerned with the use of magnesium compounds as absorbents, primarily for SO_2 but conceivably also for NO_x. The magnesium salts formed can be further processed so that the absorbent can be regenerated and recycled. The primary product of the process is high grade, concentrated (98%) sulfuric acid; however, liquified SO_2 could be made if a market for large quantities existed. It is also possible that elemental sulfur could be produced, either by reduction of concentrated SO_2 or by altered conditions in the magnesium sulfite calcination step. In the case of the latter route, there are too few data available to justify consideration as an alternative.

Regardless of which sulfur product is produced, the overall market outlook is questionable since the expected growth of byproduct sulfur and sulfuric acid from power plants, smelters and sour gas processing plants may result in an oversupply for many locations. With potential byproduct recovery so large [in 1970 emission of SO_2 from all domestic sources was equivalent to 50 million tons of 100% sulfuric acid (98), nearly 70% greater than the 29 million tons consumed], prices will remain under continuing pressure for some time to come and overall competition will be intense.

Obviously, not all SO_2 emissions will be recovered as marketable sulfur related products. In many cases where markets do not exist, other pollution control measures, such as low sulfur fuel or nonrecovery processes, will be utilized to reduce emission levels. For recovery processes such as magnesia scrubbing-regeneration, the best applications will probably be found in areas of growing acid consumption, in locations where solids waste disposal from nonrecovery processes will not be economically or legally acceptable, and in existing sulfuric acid plants where byproduct SO_2 can economically replace purchased sulfur as raw material.

Of particular interest with the magnesia scrubbing-regeneration process is the concept of a central processing plant for absorbent regeneration and product manufacture. The idea of combining the sulfur dioxide laden absorbent from several different emission sources, shipping to a separate, large, centralized plant for regeneration and final processing, and recycling the regenerated absorbent to the original location has considerable merit. Not only would the benefit of economy of scale be realized, but also, as compared to power plant operation, a more consistent, higher onstream time could be maintained and power companies could transfer the responsibility of chemical manufacture and marketing to a more qualified organization. Offsetting these advantages, however, is the cost of shipping material from the emission source to a central plant and back. Since the central processing concept can be applied to other sulfur dioxide control processes, an important part of this report will be to evaluate the economics of the procedure.

In the last few years, the technology of SO_2 control by stack gas scrubbing has progressed from the pilot plant to the demonstration stage for several of the more promising processes. The magnesia scrubbing-regeneration process is one of those which has seen rapid development and for which a demonstration unit has been built on a Boston power plant. For a process to be successful, large-scale operation over long periods will be required to prove equipment performance and reliability. Removing the relatively small quantity of sulfur dioxide (0.1-0.4%) from a large quantity of gas (3 million actual cubic feet/minute for a 1000-mw unit) is a difficult task, and it is desirable that it be accomplished at a reasonable cost without interfering unduly with the production of power.

HISTORY AND STATUS

Perhaps the earliest use of the magnesium compounds involved in this study was medicinal. In the period 1558-1603, magnesium sulfate or epsom salts were found (91) by the Europeans to have value as a cathartic medicine. Later in 1843, magnesium oxide was discovered by A. Scacchi (66) near Mount Vesuvius and since has been widely used in firebricks or refractories.

The first industrial use of magnesium sulfite or bisulfite occurred around 1874 (45) when C. D. Ekman, a Swedish chemist, built the first sulfite paper pulp mill at Bergvik, Sweden. Initially, magnesium bisulfite was used as a base for the preparation of cooking liquor; however, as the sulfite pulping process developed into widespread use, limestone became the primary material because of availability and low cost.

In the earlier pulp mills, disposal of the used cooking liquor was directed into available watercourses, but as time passed this became objectionable and ways were sought to recycle or utilize the waste materials. About 1936, G. H. Tomlinson of Howard Smith Paper Mills, Ltd., found that when magnesia-base liquor is burned for heating value, magnesium oxide is formed and sulfur dioxide is liberated (92). In addition, he found that the magnesia-base liquors could be evaporated to a high concentration with comparative freedom from scale formation. These discoveries became the basis for a new cyclic process for pulping wood. A patent (U.S. 2,285,876) covering the process was issued to G. H. Tomlinson in 1942.

The first pilot plant for the pulping process was installed as a joint venture of the Howard Smith Paper Mills, Ltd., and The Babcock and Wilcox Company in 1937 at a Canadian paper mill. About the same time, the Weyerhaeuser Paper Company was independently developing the same process. Inasmuch as the three companies had common objectives, further duplication of effort was eliminated by working out a cooperative arrangement. As a result, the Longview, Washington, mill of Weyerhaeuser became the first commercial system to utilize cyclic magnesia-base pulping. Briefly, the modern process consists of concentrating the cooking liquor in multi-effect evaporators and burning it in a heat recovery furnace to form MgO dust and SO_2 laden stack gas. The MgO dust is collected, slurried in water, and routed to a series of venturi scrubbers to form more cooking liquor by absorbing the SO_2 from the stack gas. The acid bisulfite is then fortified in a separate tower to a pH of 4-5 with makeup SO_2 from burning sulfur and recycled to the pulp mill. A generalized flowsheet is given in figure 1. Approximately 15 such systems are in use around the world.

In 1929, another use of magnesium sulfite-bisulfite solution was patented (U.S. 1,865,224), based on production of magnesium sulfate by air oxidation. A considerable

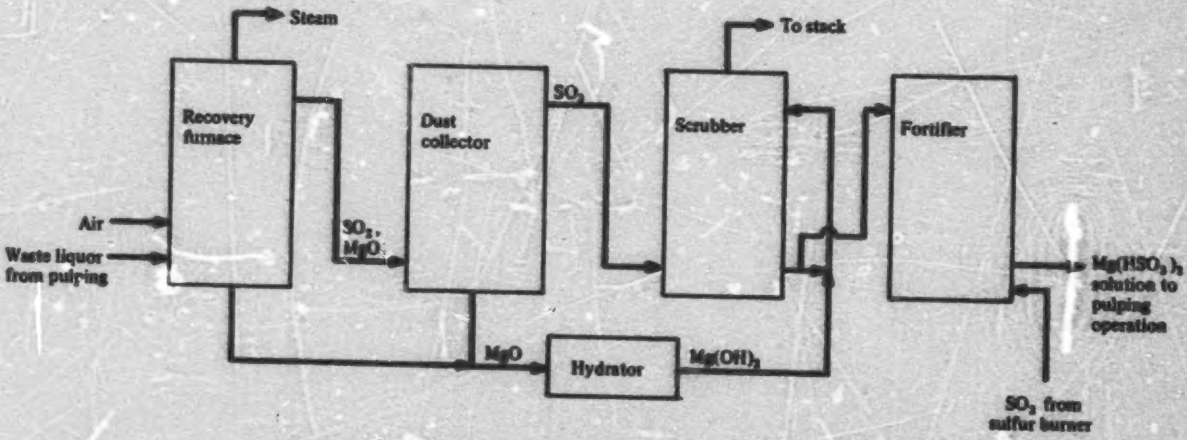

Figure 1. Magnesium bisulfite pulping process with chemical recovery.

amount of technology relating to sulfite-bisulfite formation was described in the patent (97).

The Russians were probably the earliest to consider the use of magnesia liquor or slurries for sulfur dioxide removal from smelters or power plant stack gases. Russian research (66) on processes for stack gas control began in the early thirties under the organizations of NIIOGAZ (Scientific Research Institute for Industrial and Sanitary Purification of Gases) and AUTI (All-Union Thermotechnical Institute). Several processes were studied in the laboratory, including the magnesia method. For verification on a large scale, a magnesia scrubbing pilot plant was built in 1937 at the Kashir power station. The plant was operated during 1938 and part of 1939 with reasonable success and, according to references, an industrial size system similar to that shown in figure 2 was built thereafter at one of the Russian power stations.

Soviet investigators have continued to supply research data on SO_2 removal processes throughout the years, including a great deal of information on the chemistry of magnesia slurries. Some of this will be reported and discussed in the section on Process Chemistry, Properties and Kinetics. In recent years, they are reported to have adapted the process to smelter waste gases from the Magnitogorsk Metallurgic Works (15) to produce around 100,000 tons/yr of concentrated sulfuric acid.

The Japanese have also been active in investigating the chemistry and application of the magnesia process. In the early thirties, Hagisawa (38) produced considerable data on magnesium sulfite solubility and hydrate formation. In later years, Okabe and Hori (67) investigated mangesium sulfite decomposition. Recently, it was reported that Showa Denko (82) was working on a dry, fluid-bed absorption process using magnesium oxide with subsequent regeneration. A small test unit (100 cubic meters/hr) has been built at Chiba City for demonstration. Another Japanese Company, Kawasaki Heavy Industries, Ltd., has been carrying on basic research (Japanese patent 577,159) on the magnesia scrubbing-regeneration process and is now marketing a system very similar to those developed by the Russians and Americans.

A German company, Grillo-Werke AG (61), has also developed a commercial magnesia process using naturally occurring magnesium sulfate-monohydrate (kieserite) and manganese dioxide (pyrolusite) as raw materials; however, the process can also utilize calcined magnesite (magnesium oxide) or magnesium hydroxide. The Grillo work was started in 1964 with financial support from the Labor and Social Ministry of the State of Nordrhein-Westfalen (West Germany) and Firma Union Rheinische Braunkohlen Kraftstoff AG, Wesseling. Almost all early development covered oil-fired power plant installations; however, recent

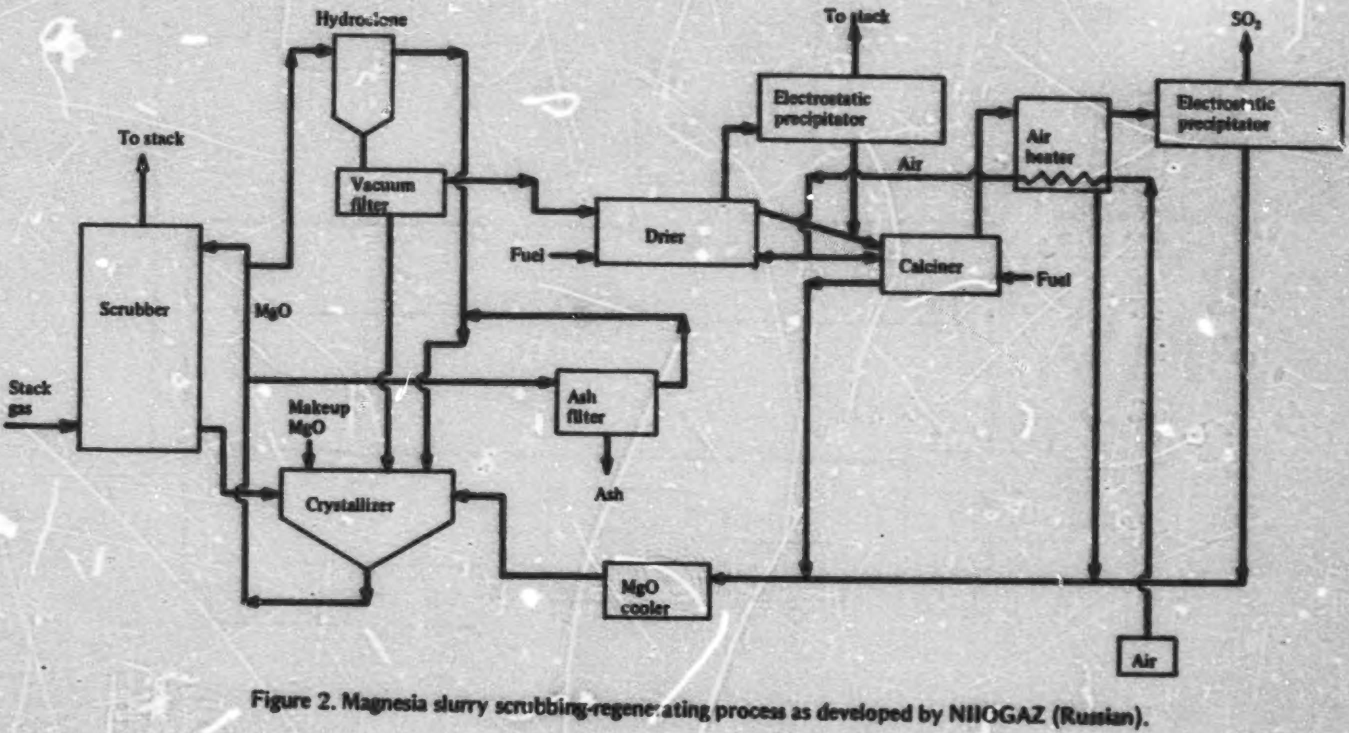

Figure 2. Magnesia slurry scrubbing-regenerating process as developed by NIIOGAZ (Russian).

work indicates that with provision for fly ash removal, the process can be adapted to coal-fired units.

Initial work on the Grillo process was on a laboratory scale with later testing in a 25,000 cubic meters/hr pilot plant at Duisburg-Hamborn. Since the Hamborn experiments were made with simulated waste gas, it was decided to test the process under actual conditions. The pilot plant was moved to an oil-fired power station at Wesseling. Overall, process development was considered a success, and in 1969 the process technology was made available. A flowsheet as proposed by Grillo is given in figure 3.

In the United States, development of the magnesia scrubbing-regeneration process for SO_2 control has been undertaken primarily by two companies--Chemico-Basic (a joint company formed by Chemical Construction Corporation, New York, and Basic Chemicals, Cleveland, Ohio) and Babcock and Wilcox Company, Barberton, Ohio. In addition, a contractor-constructor, United Engineers and Constructors, Philadelphia, has recently become actively involved in design technology.

Some basic research related to magnesium sulfite has been carried out at TVA in recent years (1969-71), partly under EPA contracts and partly under separate in-house investigation. Hatfield, Jordan, *et al* have studied $MgSO_3$ calcination, solubility, and hydrate formation. Most of their findings are presented in the Process Chemistry, Properties and Kinetics section of this report.

Esso Research and Engineering Company in their EPA-sponsored (3) study of NO_x control from stationary sources recognized the possibility of using a magnesia scrubbing system for NO_x control. Although the extent of their research in this area is not known, it can be assumed some investigation has been made. Babcock and Wilcox, under a recent EPA-funded contract, has completed pilot plant studies of NO_x removal by magnesia scrubbing; however, the preliminary results are not encouraging (26).

Chemico-Basic was the first U. S. company to market a complete magnesia scrubbing-regeneration process for sulfuric acid production using SO_2 from power plants, smelters, or sulfuric acid plant waste gases. It has completed pilot-plant test work at several locations, including particulate scrubbing at the Holtwood Station of Pennsylvania Power and Light; Crane Station of Baltimore Gas and Electric; and Dickerson Station of Potomac Electric Power;

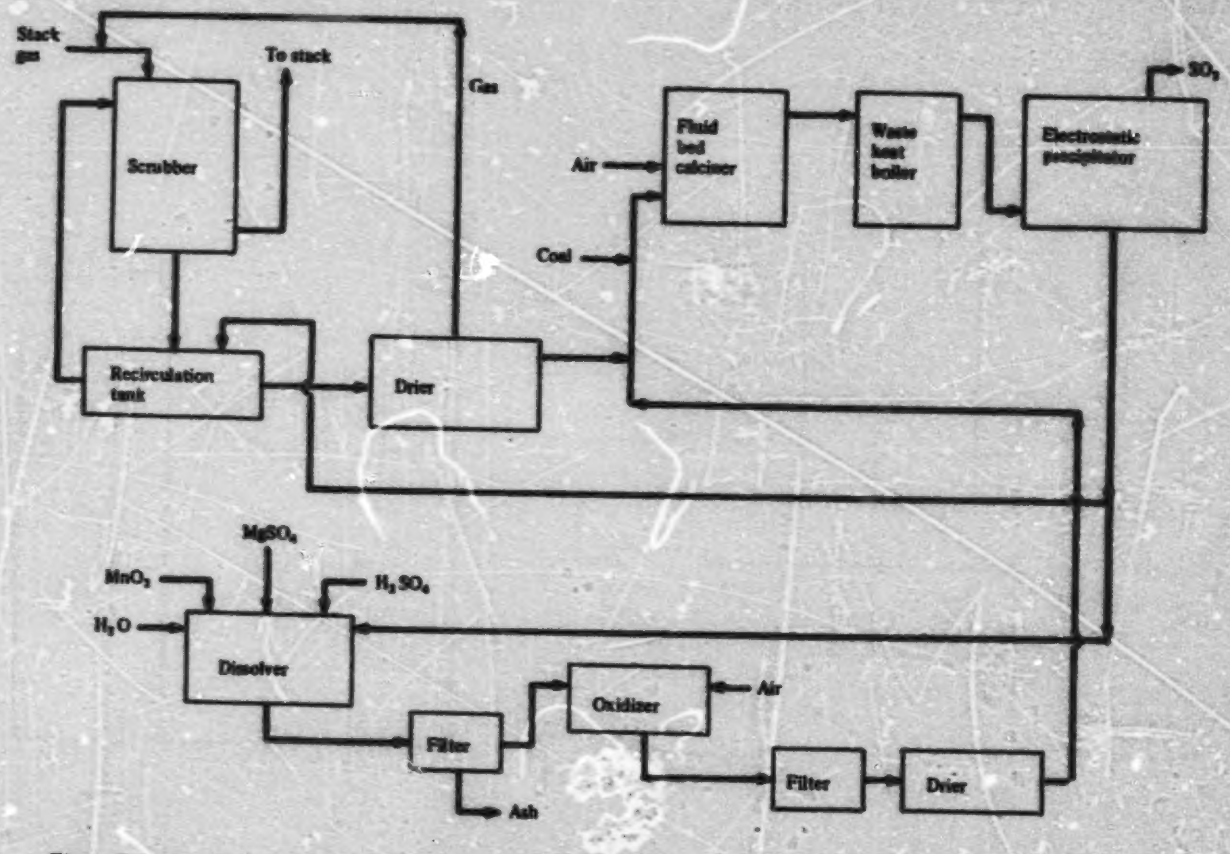

Figure 3. Magnesia-manganese dioxide slurry scrubbing-regeneration process as developed by Grillo-Werke AG.

and SO_2 scrubbing at Canal Electric Company, Sandwich, Massachusetts; Olin Corp. (sulfuric acid plant) in Baltimore, Maryland; and Cleveland Electrical Illuminating Company in Cleveland, Ohio. Most of these pilot plants processed about 1500 cfm of gas or 0.50-0.75 megawatt equivalent.

Chemico-Basic has made tests on both oil- and coal-fired systems; on coal systems, fly ash is either removed before SO_2 scrubbing or a special single scrubber technique is used. Almost all of Chemico-Basic's work has been with venturi type scrubbers; some of the results will be presented in the Equipment Selection and Description section. Patents issued to I. S. Shah (79) generally cover the Chemico-Basic process and technology.

Recently, the Babcock and Wilcox Company entered the market for complete power plant systems for SO_2 removal, based on their extensive background in magnesium sulfite pulping and chemical recovery. For many years B and W scientists and engineers have been involved with research and development in this area and have published considerable chemical and physical data on magnesium sulfite, bisulfite, and sulfate solutions, including vapor pressure and solubility relationships as a function of temperature and solution composition.

One of the more important contributions of the Babcock and Wilcox Company in this field is the magnesia slurry scrubbing study (27) completed in 1970 for the Office of Research and Monitoring of the Environmental Protection Agency (formerly the National Air Pollution Control Administration). In a study carried out in a pilot plant (2000 acfm) at the Alliance, Ohio, Research Center, data were obtained on both particulate and SO_2 scrubbing in a venturi type scrubber and SO_2 removal in a mobile bed scrubber (termed Floating Bed Absorber). Tests were made of the effect of SO_2 removal on liquid-gas ratio, pressure drop, slurry composition (including pH and sulfate concentration), stoichiometry, fly ash, preslaking of MgO, and scrubber liquid residence time. In addition, evaluations were made of the scaling problem, SO_3 formation in the coal burners, and NO_X removal. Although the early 1970 results for NO_X removal were inconclusive for the most part, the particulate and SO_2 removal data can be used for the design of power plant scrubber systems; a considerable part of this will be presented in the Equipment Selection and Description section of this report. As stated earlier, a new research project has recently (1972) been completed on NO_X removal and the preliminary results (26) will be discussed in a later section.

Because of the advanced development of the magnesia process, it has been selected by the EPA as one of the more promising SO_2 control processes ready for demonstration in a commercial size installation. In July 1970, EPA, an electric utility company (Boston Edison), a design engineering firm (Chemico-Basic), and one chemical company (Essex Chemicals) combined as a group to fund, design, build, and operate a magnesia scrubbing system at Boston Edison's Mystic Station No. 6, a 155-mw steam generating unit located in Everett, Massachusetts. The station, an oil-fired facility, will be equipped with a venturi scrubber system to remove SO_2 from the stack gases. An artist's concept of the installation is shown in figure 4. The magnesium sulfite slurry formed will be dewatered and dried and the crystals will be shipped to an existing sulfuric acid plant owned by Essex Chemical Corporation located at Rumford, Rhode Island. There the material will be calcined to release SO_2 for the 98% acid unit and the resultant magnesium oxide will be shipped back to the power plant.

Funding for the project will be approximately \$5 million, with Boston Edison paying about half and EPA the remainder. Financial support will also be provided by the Eastern Utilities Associates, the New England Gas and Electric Association, and Montaup Electric.

According to Chemico-Basic, the project will take 15 months to build, with operation planned for 1 or 2 years. The system started up in early 1972.

During the 2-year period, a program will be undertaken to test various operating parameters, optimize emission control under a power plant operating cycle, demonstrate reliability, and accurately define system operating cost. At the end of the test and evaluation program, a report will be prepared presenting the results.

A second system utilizing magnesia slurry scrubbing was recently announced by Potomac Electric Power Company for their Dickerson, Maryland station, Unit No. 3. Half of a 195-mw coal-fired unit will be equipped with a 2-stage venturi scrubber system to remove both particulates and SO_2. Particulate removal is expected to exceed 99%, and SO_2 removal will be 90% plus.

Approximately 250,000 actual cubic ft/minute of stack gas (at 259 °F) will be scrubbed in a single train with the other half of the gas being passed through an existing precipitator for dust removal prior to remixing with the scrubbed gas.

The magnesium sulfite from the SO_2 scrubber will be dewatered, dried, and then shipped to the Essex Chemical's sulfuric acid plant in Rhode Island for processing in the EPA unit associated with the Boston Edison project. Potomac Electric Power Company will fund the scrubbing portion of the system and Chemico will design and build it.

At this time, there are several potential applications of magnesia scrubbing in the offing, however, most have not been announced publicly. Perhaps final decisions are pending further on-site plant development test results. It can be stated that Grillo is currently evaluating a system for a process heat boiler at a German oil refinery. The installation is reportedly sized at about 100,000 NM^3/hr (59,000 cfm).

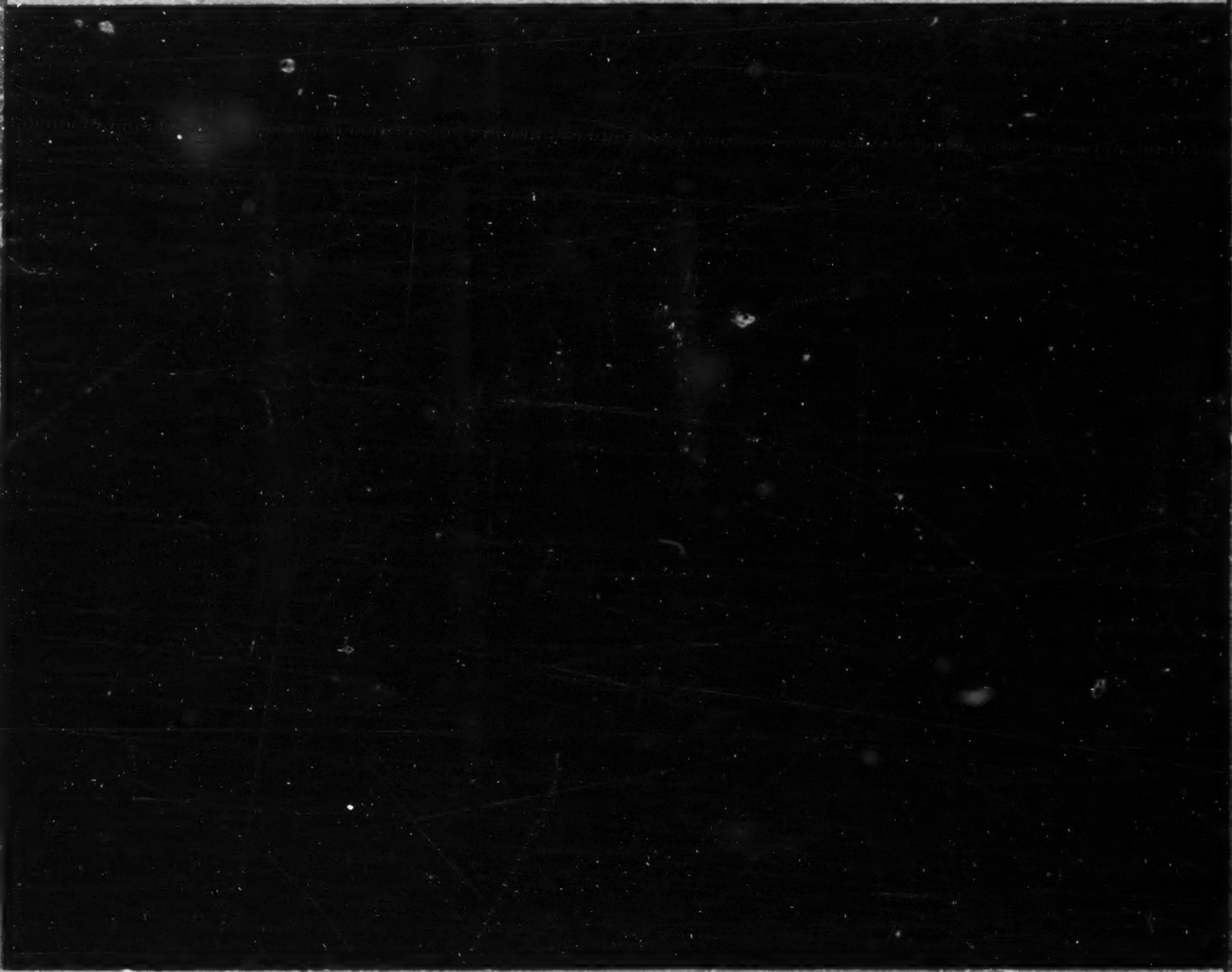

Figure 4. 150-mw prototype MgO-SO_2, recovery scrubbing system at Boston Edison Co.–Mystic No. 6, Boston, Mass.

PROCESS VARIATIONS

In the development of the magnesia scrubbing-regeneration concept both process and equipment variations have been pursued. Such process variations as raw material used or process chemistry utilized; slurry, solution or solids scrubbing of gases; and the choice of sulfur dioxide removal with or without nitrogen oxide control are considered in this section. Differences attributable to equipment alternatives such as scrubber selection, slurry dewatering devices, dryer and calciner design and type of sulfuric acid plant (wet gas or dry gas) are considered separately in a later section. Other variations possible with the magnesia scrubbing-regeneration process are the choice of product—sulfuric acid, liquid sulfur dioxide, elemental sulfur, or a related fertilizer—and physical location of facilities (on-site production vs off-site, centralized regeneration-acid manufacture); however, for most of the process schemes studied, these will be considered as economic choices rather than technological variations. Sulfur dioxide (relatively concentrated at 14-16%) is evolved from the loaded absorbent in almost all the schemes and can be further processed to any of these products at the same or different sites as the scrubbing operation. An exception, which will be covered in this section, is the possible direct reduction of magnesium sulfite-sulfate to produce elemental sulfur in the calcination step.

The Magnesia Slurry Process

The magnesia scrubbing-regeneration process on which most attention is being focused provides for aqueous slurry scrubbing of sulfur dioxide with a mixture of reacted, undissolved magnesium sulfite, dissolved sulfite-sulfate, and unreacted magnesium hydroxide. The process is shown in figure 5 as used by Chemico-Basic in the first commercial demonstration unit at Boston Edison's Mystic Station. With the exception of equipment choices, the Russian process (see figure 2, History and Status section) and the Japanese (Kawasaki) process appear to be very similar.

In the slurry process, fly ash from coal-fired systems is first removed in a particulate scrubber along with some of the SO_3 in the stack gas. The ash-water mixture is thickened, with the underflow sent to a pond for neutralization, if required, and settling; the clarified pond water is returned to the particulate scrubber for reuse. For oil-fired systems, the particulate scrubber is not required, since the amount of ash in the stack gas is less than the proposed emission standard.

To remove SO_2, the humidified and relatively dust-free gas is scrubbed in a second device with circulating $MgSO_3$-MgO base slurry having a pH between 6.5-8.5, capable of SO_2 removal of better than 90%. Crystals of hydrated $MgSO_3$, plus $MgSO_4$ formed by oxidation, are withdrawn in a side stream (10-15% solids) to a dewatering system consisting of one or more items of equipment such as a hydroclone, screen, thickener, or filter; clarified liquor is returned to the scrubber. At this point in the process, any contaminants accumulated over a period of continuous MgO recycle can be removed. After further dewatering in a centrifuge, the crystals are fed to a dryer for dehydration. Dryer offgas can be used to partially reheat the main stack gas stream.

Dried $MgSO_3$-$MgSO_4$ is next fed to a calciner, where coke/carbon is introduced to reduce the sulfates and the mixture calcined at 1400-1600° F to evolve SO_2 and regenerate MgO for recycle to the scrubber system. The calciner exit gas usually contains 10-16% SO_2 by volume depending on heat losses, the amount of coke added for $MgSO_4$ reduction, and the provision for exhaust heat utilization (feed preheat). Dust in the SO_2 offgas is removed by precipitator, bag filter, or wet scrubber and returned to the system; the cleaned SO_2 laden gas is then processed into sulfuric acid, liquified SO_2, or elemental sulfur.

The Grillo Variation

In a variation of the basic magnesia slurry process, Grillo-Werke AG, a German company, has developed a slurry scrubbing system that utilizes manganese oxides in magnesia scrubbing slurry. Although the process was developed on an oil-fired system, the addition of a particulate scrubber should permit adaptation to coal-fired stack gas. Grillo also utilizes two naturally occurring minerals, kieserite (magnesium sulfate monohydrate) and pyrolusite (87% manganese dioxide); however, magnesium oxide could be substituted for the kieserite.

A generalized flow diagram as originally proposed by Grillo is shown in figure 3, History and Status section. Absorption of SO_2 is carried out in a cocurrent or countercurrent spray scrubber having a gas velocity of

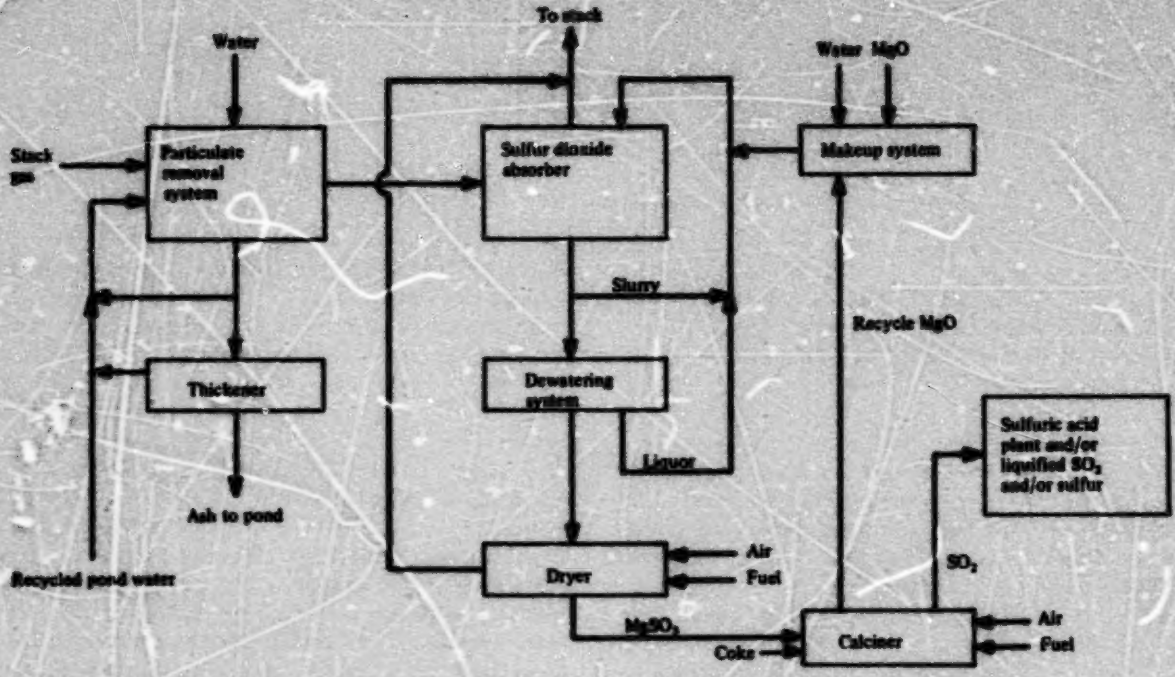

Figure 5. Magnesia slurry scrubbing-regeneration process as developed by Chemico-Basic.

about 10-18 meters/second (33-60 ft/sec) with a residence time of 0.5-1.0 second. A circulated slurry composition of 3-6 moles of MgO/mole of MnO_2 with a pH of 6.0-7.5 is used. The manganese dioxide is said to allow use of smaller scrubbers with a low L/G (approximately 6 gals/Macf) and a high slurry solids concentration (30-70%). Furthermore, the manganese compounds are reported to promote calcination of $MgSO_4$ without carbon addition at a temperature of 1800°F. The manganese oxides have been known, however, to promote oxidation in some scrubbing systems and, therefore, might increase $MgSO_4$ formation. Another problem arises from the large amount of inert material that enters the process from the pyrolusite and kieserite makeup and must be removed from the system to prevent buildup to intolerable levels. This problem would be reduced if refined MgO and MnO_2 were used as raw materials.

In general, most of the process equipment for a system similar to that developed by Grillo could be the same as for the basic slurry process. The only apparent differences occur in the scrubber-mist eliminator design, the calcination operation, and possibly in a decontamination system which might need to be larger.

The Clear Liquor Process

Another process alteration, one investigated by Chemico-Basic and possibly others, is the "clear liquor process" in which an acidic solution of soluble magnesium bisulfite, sulfite, and sulfate is used to scrub SO_2 from the stack gas. A possible use of such a process would be in coal-fired systems where only one scrubber removes both the particulate and SO_2 removal. A flow sheet of the process is shown in figure 6.

A clear solution is used so that the ash can be filtered out; however, a lower pH (less than 6.0) is required in order to get high enough solubility to keep the sulfite formed in solution. It should be mentioned that the low pH will result in greater bisulfite formation thereby increasing the vapor pressure of the scrubbing solution and restricting efficiency to less than that possible with the slurry process.

A "clear liquor process" also requires a separate step for sulfite precipitation which, after ash removal, is accomplished in a reaction tank by the addition of MgO or $Mg(OH)_2$. A pH change occurs in which the bisulfite is converted to sulfite, causing $MgSO_3 \cdot 6H_2O$ to crystallize from the liquor. The liquor is returned to the scrubber system and the $MgSO_3 \cdot 6H_2O$ crystals are processed as in the basic slurry system—that is, dewatered, dried, and calcined to evolve SO_2 and regenerate MgO for recycle. In addition to the lower SO_2 removal efficiency, the greater likelihood of fly ash solubilization could increase process contamination. Despite these drawbacks, the process may have application on power units having limited space and,

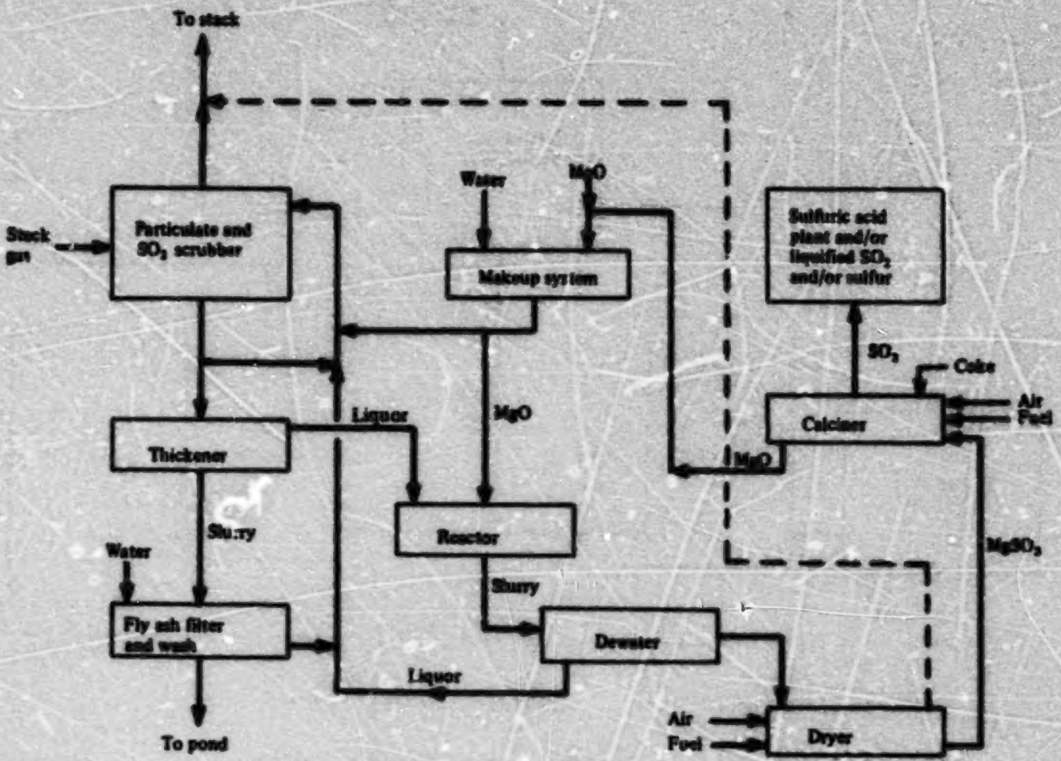
To stack
Stack gas
Particulate and SO_2 scrubber
Water
MgO
Makeup system
Sulfuric acid plant and/or liquified SO_2 and/or sulfur
SO_2
Coke
Air
Fuel
Calciner
Liquor
MgO
Thickener
MgO
Reactor
Slurry
Water
Slurry
$MgSO_3$
Fly ash filter and wash
Dewater
Liquor
Air
Fuel
Dryer
To pond

Figure 6. Clear liquor variation of magnesia scrubbing-regeneration process.

therefore, will be given full economic evaluation later in this report.

The Showa Denko Process

As mentioned earlier, sorption of SO_2 by finely divided MgO (dry system) has been tested in Japan by Showa Denko. A flowsheet is shown in figure 7. MgO is circulated through an adsorption tower until a portion is converted to $MgSO_3$ and $MgSO_4$. A side stream is withdrawn and calcined with the resultant SO_2, MgO, and undecomposed sulfites and sulfates flowing to a dust collector where the solids are separated and recycled to the absorber; the SO_2 is then processed as desired. In bench scale tests sulfur dioxide removal has been reported as near 80%.

This process has several advantages, including:

1. No need for stack gas reheat.
2. No energy required for drying free or hydration water from $MgSO_3$.
3. Reduced corrosion and erosion.

Offsetting problems include:

1. Difficulty in getting complete dust removal from the absorber exhaust precipitator because of the high resistivity of the magnesium solids.
2. High internal recycle required.
3. Loss of absorbent efficiency over extended cycles of sorption and regeneration.
4. A need for an impurities purge to prevent intolerable buildup of inerts and contaminants.

The process is in such a preliminary stage of development, as compared to the aqueous scrubbing techniques already described, that it is not given serious consideration in this report. If progress is continued on the development of a dry process, it may be worthwhile to study such a concept separately.

NO_x Removal Process

Use of magnesia scrubbing for NO_x control has been described in the Esso Research and Engineering Study for EPA, "Systems Study of Nitrogen Oxide Control Methods for Stationary Sources" (3), and the Babcock and Wilcox-EPA study of scrubbers for SO_2 removal by the magnesia process (27). This process utilizes magnesium sulfite slurry scrubbing for SO_2 removal and magnesium hydroxide for NO_x absorption. A generalized flow diagram is shown in figure 8.

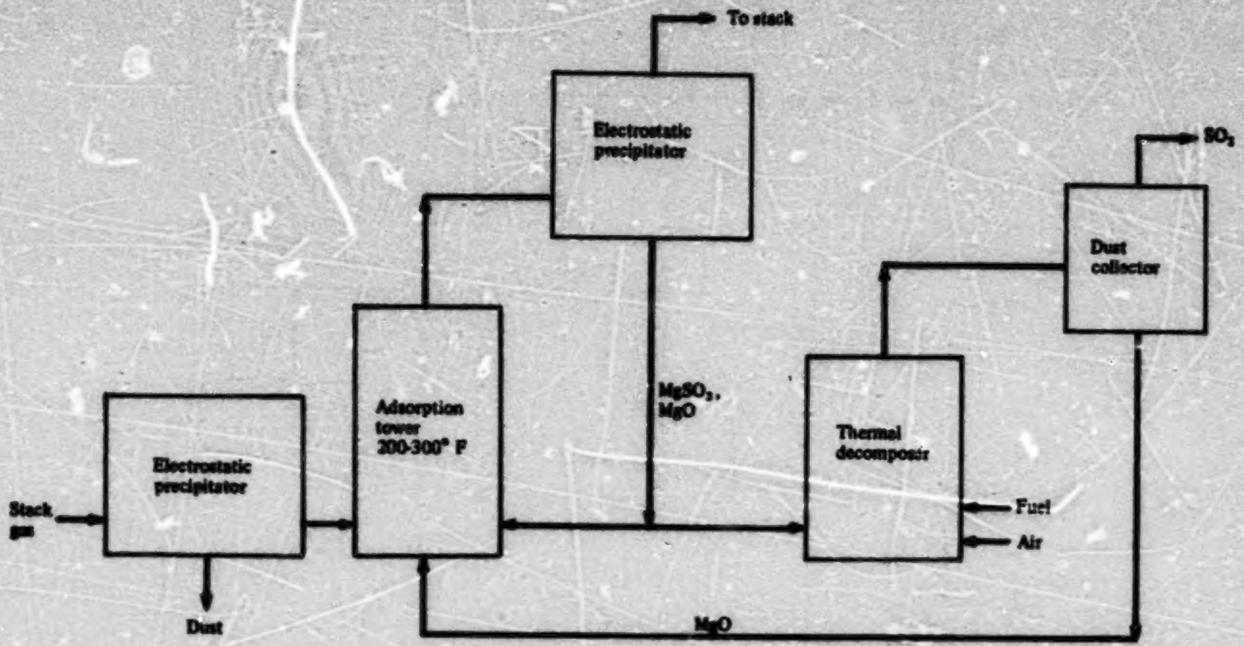
To stack
Electrostatic precipitator
SO₂
Dust collector
Adsorption tower 200-300° F
MgSO₃, MgO
Thermal decomposer
Electrostatic precipitator
Stack gas
Fuel
Air
Dust
MgO

Figure 7. Showa Denko dry MgO process for SO_2 removal.

The sulfur oxides removal system must precede the NO_X removal section for the process to function. For best results, the NO_X system requires the recycle of nitrogen dioxide to obtain an equimolar mixture of NO_2 and NO, forming N_2O_3 which can be absorbed more effectively than either NO or NO_2 alone. The recycle of NO_2, however, would oxidize SO_2 in the gas to SO_3 as in equation 1 resulting in sulfate formation and little NO_X removal.

$$NO_2 + SO_2 \rightarrow SO_3 + NO \qquad (1)$$

When most of the SO_2 is removed prior to addition of NO_2, however, the process might work as outlined in equations 2 and 3.

$$Mg(OH)_2 + N_2O_3 \rightarrow Mg(NO_2)_2 + H_2O \qquad (2)$$

$$3Mg(NO_2)_2 + \text{heat} + 2H_2O + \text{pressure} \rightarrow Mg(NO_3)_2 + 2Mg(OH)_2 + 4NO \qquad (3)$$

The NO would be oxidized and recycled to the absorber and the magnesium nitrate ammoniated to yield ammonium nitrate.

$$Mg(NO_3)_2 + 2NH_3 + 2H_2O \rightarrow 2NH_4NO_3 + Mg(OH)_2 \qquad (4)$$

The ammonium nitrate is a salable fertilizer product, and the insoluble magnesium hydroxide could be recycled to the scrubber system.

So far, this procedure can not be considered seriously since preliminary test results from the 1972 EPA-Babcock and Wilcox program (26) were discouraging; however, the chemistry of this procedure will be given further treatment in the Process Chemistry, Properties and Kinetics section of this report.

Direct Sulfur Production in the Calciner

It is known that several investigators are currently working on a magnesium sulfite calcination step which would yield sulfur directly instead of SO_2. As will be shown in the section on Process Chemistry, Properties and Kinetics, Sillen and Andersson (81), two Swedish researchers, predicted that it is possible to get H_2S and MgO in a calciner by operating under strongly reducing conditions at lower temperatures. It is conceivable that elemental sulfur could be made in the calciner under some condition; however, in view of the relatively low concentration of SO_2 (10-15%) produced with direct calcination, the procedure could be difficult. A possible process might be developed using an indirectly heated calciner, an inert gas sweep, and operating at a temperature in which sulfate, thiosulfate, and MgO could be produced. The thiosulfate might be decomposed to magnesium sulfate and elemental sulfur and the two products separated.

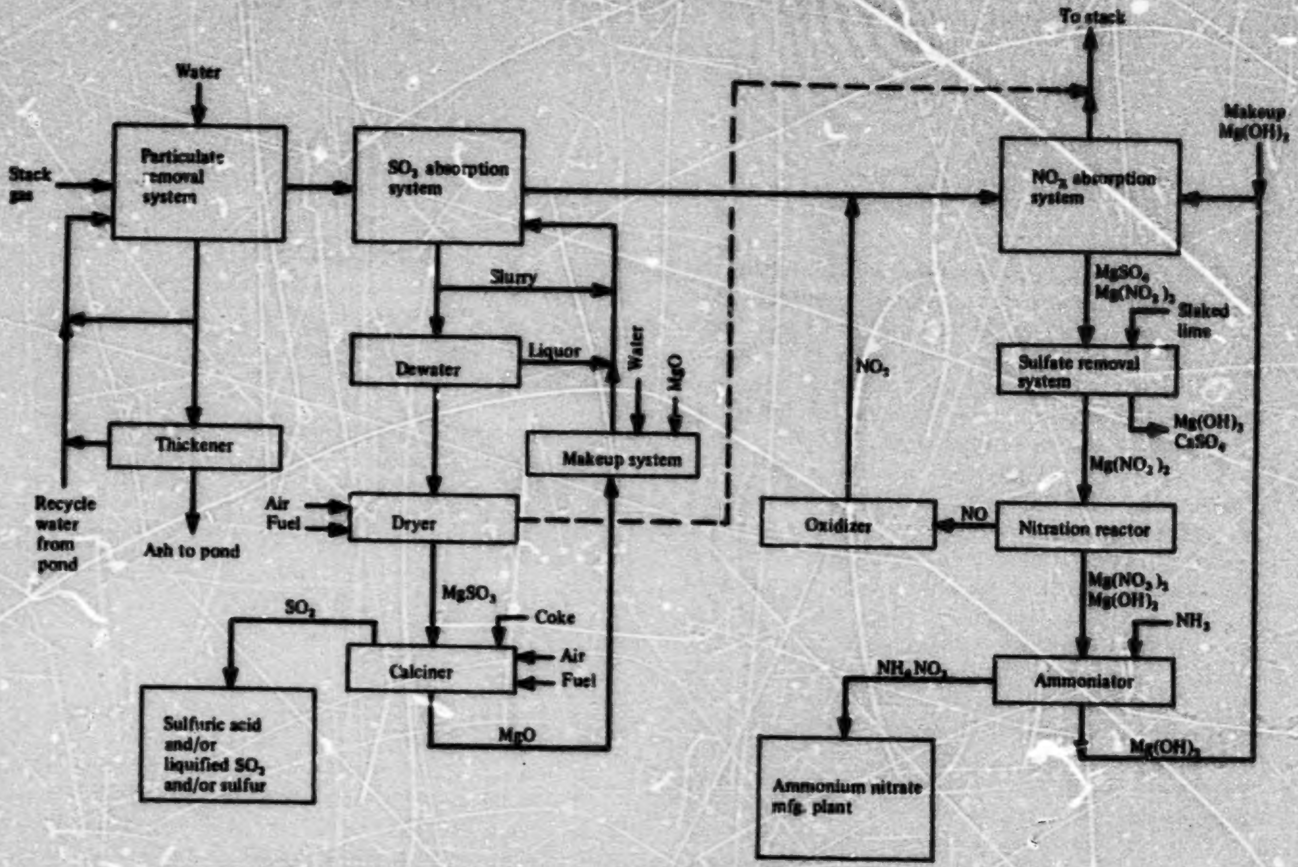
Water
Stack gas
Particulate removal system
Recycle water from pond
Thickener
Ash to pond
SO$_2$ absorption system
Slurry
Dewater
Liquor
Water
MgO
Makeup system
Air
Fuel
Dryer
MgSO$_3$
SO$_2$
Coke
Calciner
Air
Fuel
MgO
Sulfuric acid and/or liquified SO$_2$ and/or sulfur
To stack
Makeup Mg(OH)$_2$
NO$_x$ absorption system
MgSO$_4$
Mg(NO$_3$)$_2$
Slaked lime
Sulfate removal system
Mg(OH)$_2$
CaSO$_4$
Mg(NO$_3$)$_2$
NO$_2$
Oxidizer
NO
Nitration reactor
Mg(NO$_3$)$_2$
Mg(OH)$_2$
NH$_3$
NH$_4$NO$_3$
Ammoniator
Mg(OH)$_2$
Ammonium nitrate mfg. plant

Figure 8. Magnesia process for removal of both sulfur and nitrogen oxides from stack gas.

As is apparent, the scheme is in need of a great deal of research and, hopefully, additional work will be done; however, it is much too early to attempt process definition and the idea does not merit complete evaluation at this time.

A more practical scheme for sulfur manufacture has been developed by Allied Chemical (99) in which low concentration SO$_2$ from calcination can be reduced to elemental sulfur. This process should not be considered as a technological variation of magnesia scrubbing but, as stated earlier, an economic variation since many processes producing SO$_2$ could utilize the development. Chemistry of the Allied Chemical SO$_2$ reduction process will be discussed further in the section to follow.

PROCESS CHEMISTRY, PROPERTIES AND KINETICS

Some of the first chemical and physical data applicable to the magnesia process comes from the pulp and paper industry, which has long used sulfite pulping with subsequent SO_2 recovery. Because of the nature of the pulping operation, much of this information applies to magnesium sulfite-bisulfite solutions and is, therefore, more related to the clear liquor process than the slurry process.

Soviet workers, represented principally by B. A. Chertkov and V. A. Pinaev, have made large contributions to ammonia, limestone, and magnesia scrubbing of SO_2 at smelter and power plants. As early as 1940 (68), Peisakhov and Chertkov considered the use of magnesia scrubbing at the Moscow and Leningrad power plants. Japanese workers have studied the physcial properties of $MgSO_3$ and are now showing interest in the magnesia process. Johnstone at the University of Illinois worked on all phases of SO_2 scrubbing with ammonia and some of his results are applicable to the magnesia system. More recently, Shah (79), Markant (63, 64), Downs, and Kubasco (26, 27) have made substantial contributions to our understanding of the magnesia process.

There are three series of reactions which occur in the magnesia scrubbing-regeneration process. In the first series, the scrubbing step,the following reactions predominate:

Sulfur dioxide absorption, represented by the reactions:

$$5H_2O + Mg(OH)_2 + SO_2 \rightarrow MgSO_3{\cdot}6H_2O \downarrow \qquad (5)$$

$$SO_2 + MgSO_3{\cdot}6H_2O \rightarrow Mg(HSO_3)_2 + 5H_2O \qquad (6)$$

Bisulfite neutralization, represented by the reaction:

$$Mg(HSO_3)_2 + MgO + 11H_2O \rightarrow 2MgSO_3{\cdot}6H_2O \downarrow \qquad (7)$$

Magnesium sulfite oxidation, represented by the reaction:

$$2MgSO_3 + O_2 \rightarrow 2MgSO_4 \qquad (8)$$

Magnesium sulfite hexahydrate crystals are removed from the scrubbing system and either sent directly to a dryer or thermally converted to $MgSO_3{\cdot}3H_2O$ and then dried. It is possible that some $MgSO_4{\cdot}7H_2O$ and perhaps $MgSO_4{\cdot}6H_2O$ will also be occluded in the $MgSO_3{\cdot}6H_2O$. The chemical reactions which occur in the dryer are:

$$MgSO_3{\cdot}3H_2O \xrightarrow{\Delta} MgSO_3 + 3H_2O \uparrow \qquad (9)$$

or

$$MgSO_3{\cdot}6H_2O \xrightarrow{\Delta} MgSO_3 + 6H_2O \uparrow \qquad (10)$$

and

$$MgSO_4{\cdot}7H_2O \xrightarrow{\Delta} MgSO_4 + 7H_2O \uparrow \qquad (11)$$

The dry crystals are calcined at 800 to 1100° C in the presence of coke to regenerate MgO and SO_2. The reactions occurring in the calciner are:

$$C + \tfrac{1}{2}O_2 \rightarrow CO \qquad (12)$$

$$CO + MgSO_4 \rightarrow CO_2 + MgO + SO_2 \uparrow \qquad (13)$$

$$MgSO_3 \rightarrow MgO + SO_2 \uparrow \qquad (14)$$

The magnesium oxide is cycled back to the scrubber system and the sulfur dioxide is sent to a sulfuric acid plant.

The physcial properties of process compounds, chemical equilibria, kinetics, and mass transfer involved in the magnesia process have been studied and are covered in the following discussion. It will be evident that there are areas of disagreement and incomplete understanding. Of particular need for further research are impurity buildup and fly ash leaching, sulfite oxidation, and crystal growth or scaling in the scrubber systems.

Physical Properties of Process Compounds and Solutions

The nature of the process under consideration will, in part, depend on the physcial and chemical properties of process compounds and solutions. For that reason, some of the physcial properties, optical properties, solubility data and, where important, information on chemical reactivity are given below.

Solubility of Magnesium Sulfate and Magnesium Sulfite

Solubility of magnesium sulfate in water—At least four hydrates of magnesium sulfate exist between 0 and 100° C: $MgSO_4{\cdot}7H_2O$, $MgSO_4{\cdot}6H_2O$, $MgSO_4{\cdot}5$(or 4)H_2O, and $MgSO_4{\cdot}H_2O$ (59). The solubility relationships are further complicated by the great range of metastability of $MgSO_4{\cdot}6H_2O$ and $MgSO_4{\cdot}5(4?)H_2O$.

The compilation of solubility information, between 0 and 60° C, found in Link's book (59) is shown in figure 9. The transition temperature between $MgSO_4 \cdot 7H_2O$ and $MgSO_4 \cdot 6H_2O$ occurs at 48° C (118° F) and; therefore, it is possible that both phases may be present in process slurries.

Solubility of magnesium sulfite in water—At least three sources of magnesium sulfite solubility data exist (59, 64, 69), but all three data sets are in fair agreement. These are presented in figure 10. It is generally agreed that at least two hydrates exist, $MgSO_3 \cdot 6H_2O$ and $MgSO_3 \cdot 3H_2O$. In addition, Markant *et al* (64) claim evidence for two other unstable hydrates of unknown composition.

The temperature of transition between $MgSO_3 \cdot 6H_2O$ and $MgSO_3 \cdot 3H_2O$ is variously quoted as being 40° C. However, the slow rate of conversion at this temperature could make true equilibrium difficult to attain. For this reason the quoted value of 40° C may be questionable.

Hatfield (42), on the basis of solubility product calculations, also questions the value of the transition temperature as well as the composition of the solid which Hagisawa (38) claimed to be $MgSO_3 \cdot 3H_2O$. By using published thermodynamic stability constants (60) for H_2SO_3, HSO_3^-, $MgOH^+$, and $MgSO_3$, Hatfield is able to show that the solubility product of $Mg(OH)_2$ is exceeded when Hagisawa's $MgSO_3 \cdot 3H_2O$ solubility data is used. Between 42 and 50° C, Hagisawa's solutions are supersaturated with $Mg(OH)_2$ by about 15%. With increasing temperature the apparent degree of supersaturation increases until the solution is 100% supersaturated at 85° C; i.e., the calculated $Mg(OH)_2$ solubility product is half the observed value. Such supersaturation is perhaps unreasonable, and a more reasonable explanation for these disparate results is that Hagisawa's $MgSO_3 \cdot 3H_2O$ is, in fact, a mixed hydroxisulfite of some type.

It is known that $MgSO_3 \cdot 6H_2O$ precipitates in the sulfur dioxide scrubber section even when the solution temperature exceeds 50° C. There are at least two possible explanations for this:

1. Because there is a solid phase of $MgO{:}Mg(OH)_2$ in the scrubber, the stable phase on the surface of a MgO particle may be $MgSO_3 \cdot 6H_2O$.
2. The stable phase at operating temperature is $MgSO_3 \cdot 6H_2O$ and the temperature of transition exceeds 50° C.

Solubility of $MgSO_3$ in $MgSO_4$ solution—Because oxidation of sulfite can occur in the scrubber, substantial amounts of $MgSO_4$ might be present in process solutions; therefore, the influence of magnesium sulfate on magnesium sulfite solubility, vapor pressure, and other solution characteristics should be considered.

Pinaev (69) has shown that $MgSO_4$ alters the solubility of magnesium sulfite in a somewhat unusual manner. His solubility data between 0 g/l. and 200 g/l. $MgSO_4$ are shown in figure 11.

If only the common ion effect were predominant, increased $MgSO_4$ concentration would be expected to depress the $MgSO_3$ solubility; but up to 200 g/l. $MgSO_4$, $MgSO_3$ solubility actually increases. To explain the increased $MgSO_3$ solubility, Pinaev suggests the formation

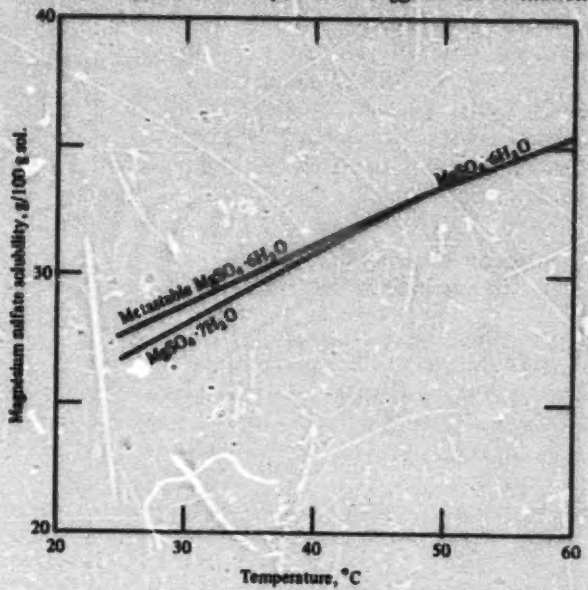

Figure 9. Effect of temperature on magnesium sulfate solubility (59).

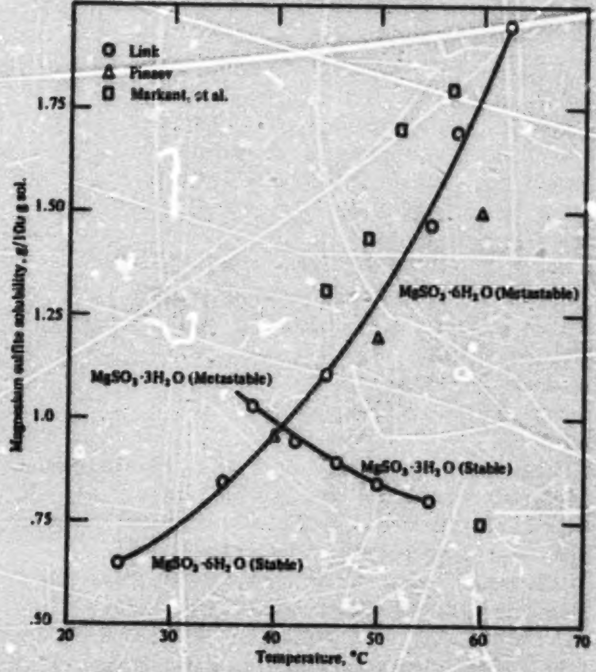

Figure 10. Effect of temperature on magnesium sulfite solubility (59) (64) (69).

of one or more complex ions. The known decrease in the activity coefficient of Mg^{++} with increased ionic strength will also account for the increased $MgSO_3$ solubility.

In pilot plant work (12), $MgSO_4$ concentration ranged from 17 g/l. to about 120 g/l. in the $MgSO_3$ slurry. Thus, actual $MgSO_3$ solubility at 50° C, for example, could be as much as 75% higher than the solubility of $MgSO_3$ in water, which is about 13 g/l.

Optical Properties and Specific Gravity of Solid Materials

Given below are the specific gravity, crystal lattice, crystal habit, and refractive indices of solid compounds encountered in the process. Unless noted, refractive indices refer to those measured in visible light.

Magnesium sulfate heptahydrate, $MgSO_4 \cdot 7H_2O$ (96)–Magnesium sulfate heptahydrate is described as orthorhombic with a = 11.94, b = 12.03, and c = 6.87. The crystals are usually prismatic and often fibrous. Refractive indices in sodium light are $n_x = 1.432$, $n_y = 1.455$, and $n_z = 1.461$. Specific gravity is 1.677.

Magnesium sulfate hexahydrate, $MgSO_4 \cdot 6H_2O$ (96)–This compound is monoclinic with a = 10.04, b = 7.15, and c = 24.34 kX. The crystals are described as thick, basal, tablets, or prismatic. $n_x = 1.426$, $n_y = 1.453$, and $n_z = 1.456$. Specific gravity is 1.75.

Magnesium oxide, MgO (96)–Magnesium oxide is isometric with the sodium chloride space lattice a = 4.203 kX. The crystals are either cubic or octahedral. The refractive index in sodium D light is 1.7366. Specific gravity is 3.56.

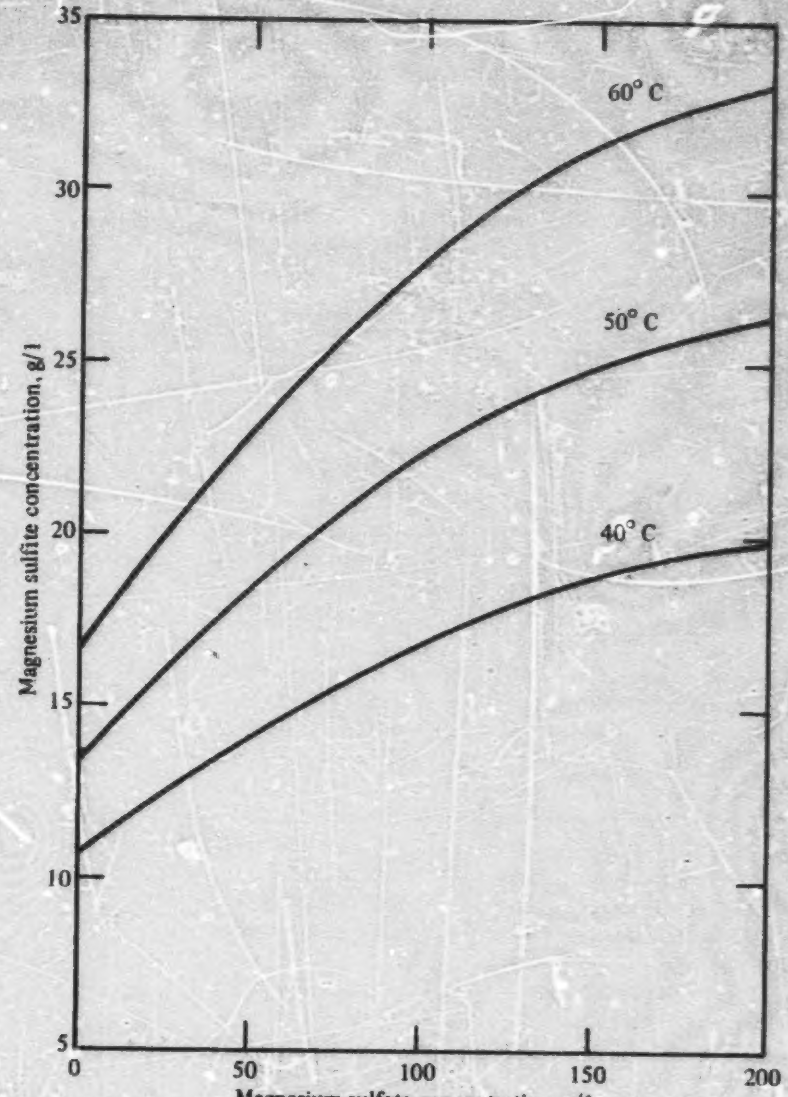

Figure 11. Effect of magnesium sulfate on magnesium sulfite solubility (69).

Magnesium hydroxide, $Mg(OH)_2$ (96)–Magnesium hydroxide is hexagonal with a = 3.12 and c = 4.75 kX. Crystals are described as basal plates with perfect cleavage. Specific gravity = 2.39 $n_o = 1.566$ and $n_e = 1.585$.

Magnesium sulfite hexahydrate, $MgSO_3 \cdot 6H_2O$ (96)–Magnesium sulfite hexahydrate is hexagonal with a = 8.82 and c = 9.04 kX $n_o = 1.524$ and $n_e = 1.474$ in blue mercury light. The specific gravity is 1.73. As shown in figure 12 at 200X, the crystals appear as hemimorphic trigional pyramids. This photomicrograph and the subsequent photographs were made with a scanning electron microscope.

Magnesium sulfite trihydrate, $MgSO_3 \cdot 3H_2O$–As shown in figure 13, at 2000X, magnesium sulfite trihydrate apparently occurs as platy prismatic pyramids. The calculated specific gravity is 2.13, somewhat higher than the density of the hexahydrate (43). $n_x = 1.552$, $n_y = 1.555$, and $n_z = 1.595$. In general, $MgSO_3 \cdot 6H_2O$ crystals are much larger and better formed than $MgSO_3 \cdot 3H_2O$ crystals. A comparison between figure 12 and figure 14, both at 200X,

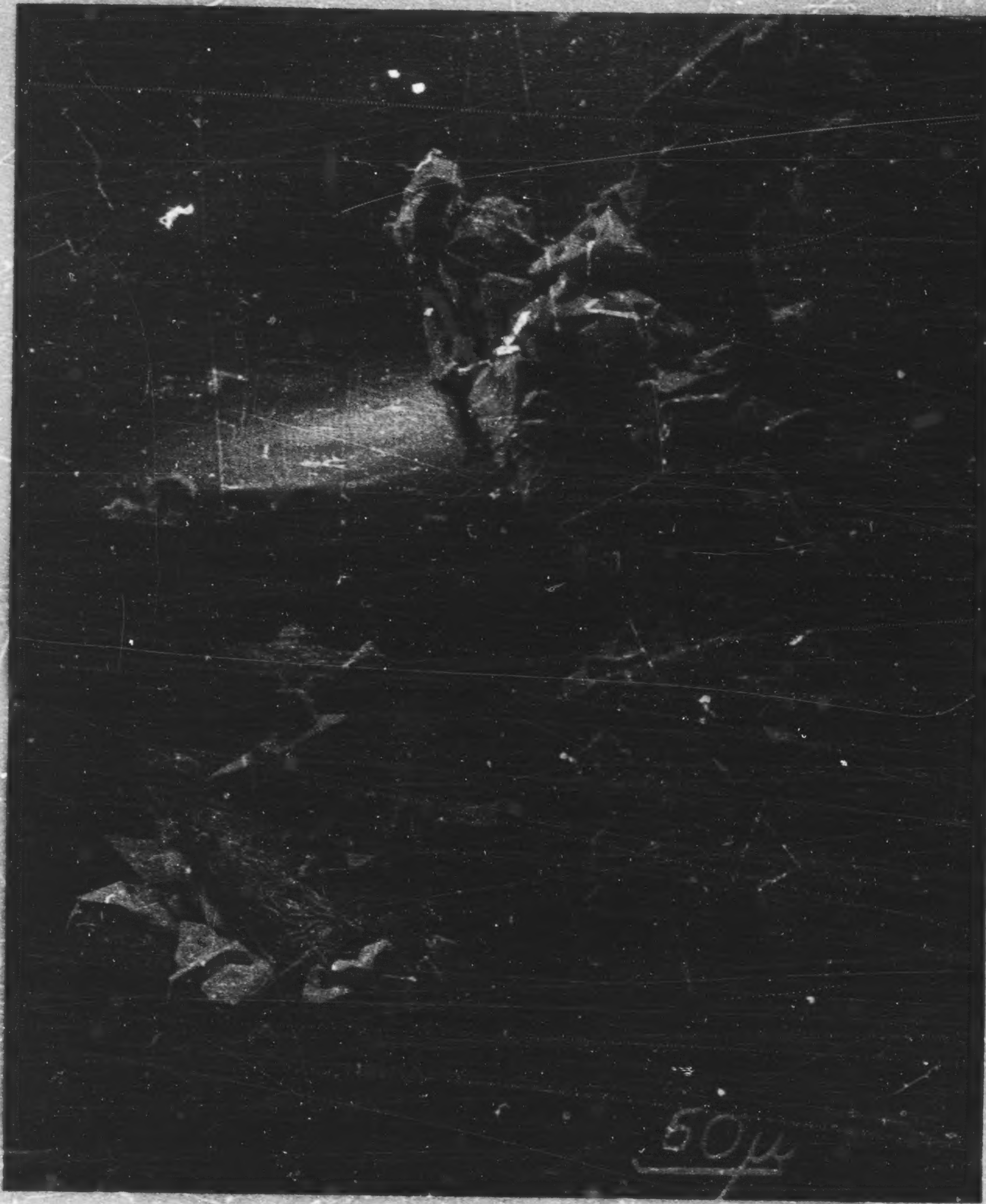

Figure 12. Photomicrograph of magnesium sulfite hexahydrate—200 X.

Figure 13. Photomicrograph of magnesium sulfite trihydrate—2000 X.

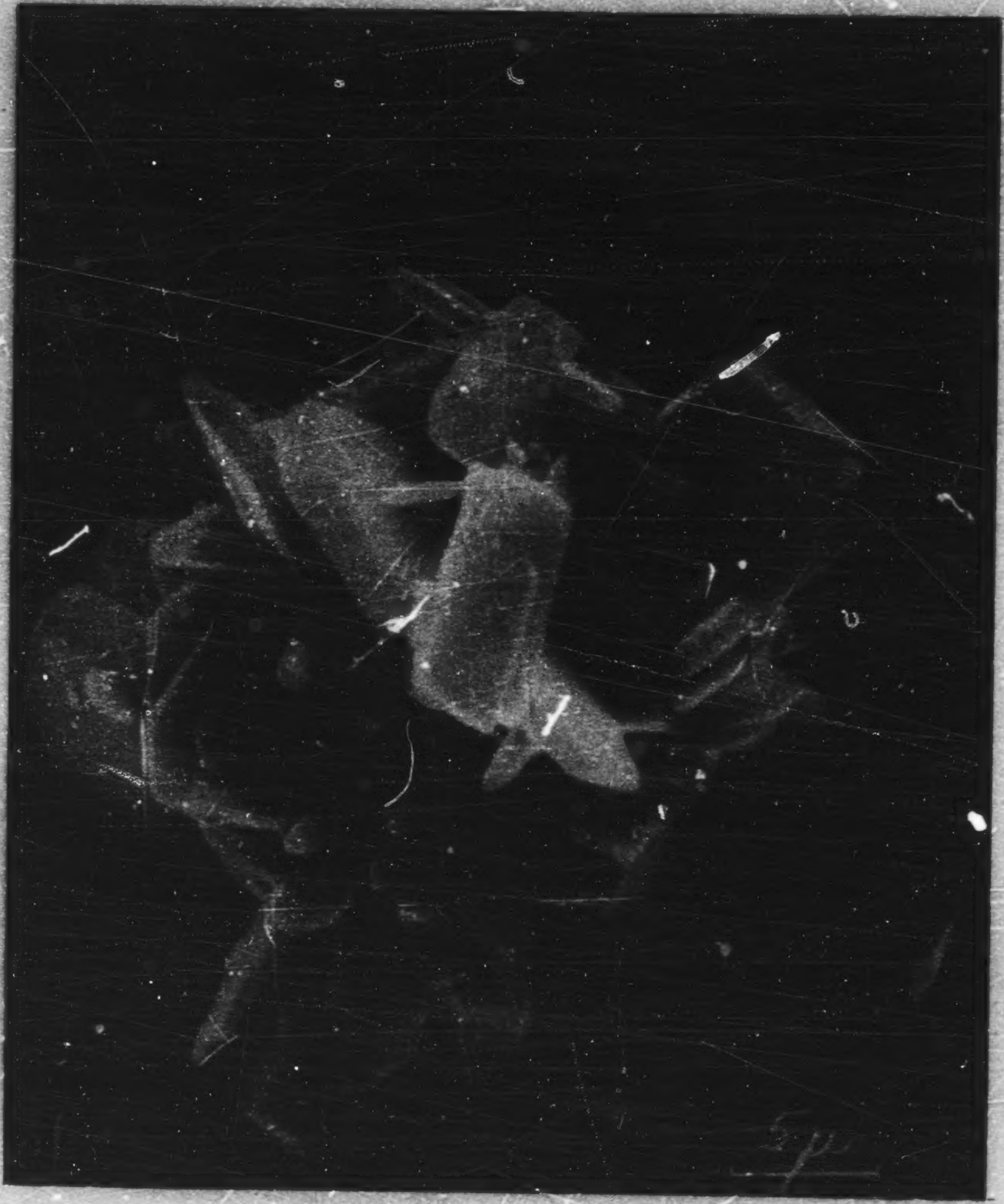

Figure 14. Photomicrograph of magnesium sulfite trihydrate—200 X.

emphasizes the great size difference between $MgSO_4 \cdot 6H_2O$ and $MgSO_4 \cdot 3H_2O$, about 10:1.

Density and Viscosity of Magnesium Sulfite—Magnesium Bisulfite—Magnesium Sulfate Solutions

Pinaev (70) has measured the viscosity and density of magnesium sulfite-bisulfite-sulfate solutions between 30 and 60° C. The data were fitted to the equations shown below by linear regression analysis.

$$\begin{aligned}\rho = {} & A_0 + A_1[MgSO_4] + A_2[Mg(HSO_3)_2] + A_3T + \\ & A_{12}[MgSO_4]\,[Mg(HSO_3)_2] + A_{13}[MgSO_4]T + \\ & A_{23}[Mg(HSO_3)_2]T + A_4[MgSO_3]\end{aligned} \qquad (15)$$

$$\begin{aligned}\zeta = {} & B_0 + B_1[MgSO_4] + B_2[Mg(HSO_3)_2] + B_3T + \\ & B_{12}[MgSO_4]\,[Mg(HSO_3)_2] + B_{13}[MgSO_4]T + \\ & B_{23}[Mg(HSO_3)_2]T + B_4[MgSO_3] + \\ & B_{44}[MgSO_3]^2\end{aligned} \qquad (16)$$

Where A_0, A_1, A_2, A_3, A_{12}, A_{13}, A_{23}, A_4, B_0, B_1, B_2, B_3, B_{12}, B_{13}, B_{23}, B_4, and B_{44} are constants; $MgSO_3$, $Mg(HSO_3)_2$, $MgSO_4$, and T represent molar concentrations and temperature in °C; and ρ and ζ are density in g/ml and viscosity in cp. The correlation coefficients and standard errors for equations 15 and 16 are, respectively, 0.9981 and 0.0016 g/ml and 0.9898 and 0.049 cp.

These equations were used to calculate the viscosity and density information found in table 1. The $MgSO_3$ concentration was held constant in the scrubber solution since it does not vary appreciably.

It has long been known that the viscosity of a disperse system, consisting of a suspension of solid particles in a dispersing liquid, has a higher viscosity than the dispersing liquid alone. Kurgaev (56) has expanded the work of A. Einstein and others to develop the equation, shown below, which relates suspension viscosity, μ_c to solution viscosity, μ_o.

$$\mu_c = \mu_o \left[1 + \frac{2C}{(1\text{-}1.2C^{2/3})^2}\right] \qquad (17)$$

In this equation, C is the volume ratio of dispersed phase particles to dispersing phase volume. In table 2, values of μ_c/μ_o are shown at several values of C.

The SO_2 scrubber system will have about 10 weight % solids, primarily $MgSO_3 \cdot 6H_2O$, which is equivalent to a volume ratio of about 0.07. The ratio of slurry to solution viscosity is 1.23, thus, slurry viscosities could be expected to exceed solution viscosities by about 23%.

Table 2. Variation of slurry/solution viscosity ratio with solid/liquid ratio.

	C = 0.05	C = 0.10	C = 0.15	C = 0.20	C = 0.25
μ_c/μ_o	1.14	1.36	1.68	2.12	2.85

Vapor Pressure of Sulfur Dioxide Over $MgSO_3$—$Mg(HSO_3)_2$—$MgSO_4$

Because scrubbing efficiency is directly related to the difference between the partial pressure of SO_2 in the stack gas and the sulfur dioxide vapor pressure over the scrubbing solution, the dependence of vapor pressure on scrubber solution composition is quite important. Kuzminykh and Babushkina (57) determined vapor pressures over $MgSO_4$-$MgSO_3$-$Mg(HSO_3)_2$ slurries of various compositions between 10 and 70° C. Their results are in good agreement with Hagisawa (39) and Yakimets (100), but differ considerably from Conrad and Brice (23).

Pinaev (71) has also measured SO_2 vapor pressure over $MgSO_3$-$MgSO_4$ slurries, but because his vapor pressure measurements are much lower than other workers, they are considered questionable.

Since pH and solution composition can be related easily Chertkov (15) reworked the data of Kuzminykh and Babushkina to point out the relationship between vapor pressure and pH. Results of these calculations, shown in figure 15, show the increase in SO_2 vapor pressure that occurs with decreased pH and increased $MgSO_4$. Similar results were found in the ammonia system (16). The effect of $MgSO_4$ on SO_2 vapor pressure is most important at lower pH.

Markant *et al* (63) measured SO_2 vapor pressure over magnesium sulfite-bisulfite solutions (not slurries) at two levels of total dissolved SO_2, 4.44% and 6.16%, and three temperatures, 100, 120, and 140° F. Results are given in figures 16 and 17.

Because of the high bisulfite to sulfite ratio, the pH of these solutions will be rather low; therefore, the data would be more applicable to a clear liquor process than a slurry process.

At constant total dissolved SO_2, vapor pressure increases with decreasing $MgSO_3$ concentration or increasing bisulfite concentration. There is a substantial increase in SO_2 vapor pressure with temperature, and as pointed out in a later section, this could adversely affect the mass transfer coefficient.

Chemistry

Slaking of MgO—Smithson and Bakhshi (85), who studied the slaking characteristics of MgO, believe two surface chemical reactions occur when MgO reacts with water and goes into solution.

$$MgO + H_2O \rightarrow Mg(OH)_2 \qquad (18)$$

$$Mg(OH)_2 \rightarrow Mg^{++} + 2OH^- \qquad (19)$$

Table 1. Viscosity and density of magnesium sulfite-bisulfite-sulfate solutions.

Temperature °C	$MgSO_4$, g/l	$Mg(HSO_3)_2$, g/l	$MgSO_3$, g/l	Density, g/ml	Viscosity, cp
40	24.9960	5.0034	5.0024	1.0072	1.0405
40	49.9920	5.0034	5.0024	1.0361	1.2543
40	74.9880	5.0034	5.0024	1.0650	1.4681
40	99.9840	5.0034	5.0024	1.0939	1.6819
40	124.9800	5.0034	5.0024	1.1227	1.8958
40	24.9960	24.9984	5.0024	1.0164	1.0710
40	49.9920	24.9984	5.0024	1.0467	1.3050
40	74.9880	24.9984	5.0024	1.0771	1.5389
40	99.9840	24.9984	5.0024	1.1074	1.7729
40	124.9800	24.9984	5.0024	1.1378	2.0069
40	24.9960	44.9934	5.0024	1.0255	1.1015
40	49.9920	44.9934	5.0024	1.0574	1.3556
40	74.9880	44.9934	5.0024	1.0892	1.6098
40	99.9840	44.9934	5.0024	1.1210	1.8639
40	124.9800	44.9934	5.0024	1.1529	2.1180
50	24.9960	5.0034	5.0024	1.0008	0.8597
50	49.9920	5.0034	5.0024	1.0300	1.0305
50	74.9880	5.0034	5.0024	1.0592	1.2013
50	99.9840	5.0034	5.0024	1.0884	1.3721
50	124.9800	5.0034	5.0024	1.1176	1.5429
50	24.9960	24.9984	5.0024	1.0099	0.8838
50	49.9920	24.9984	5.0024	1.0406	1.0747
50	74.9880	24.9984	5.0024	1.0712	1.2657
50	99.9840	24.9984	5.0024	1.1019	1.4566
50	124.9800	24.9984	5.0024	1.1325	1.6476
50	24.9960	44.9934	5.0024	1.0190	0.9078
50	49.9920	44.9934	5.0024	1.0511	1.1189
50	74.9880	44.9934	5.0024	1.0832	1.3301
50	99.9840	44.9934	5.0024	1.1154	1.5412
50	124.9800	44.9934	5.0024	1.1475	1.7523
60	24.9960	5.0034	5.0024	0.9945	0.6789
60	49.9920	5.0034	5.0024	1.0239	0.8066
60	74.9880	5.0034	5.0024	1.0534	0.9344
60	99.9840	5.0034	5.0024	1.0829	1.0622
60	124.9800	5.0034	5.0024	1.1124	1.1899
60	24.9960	24.9984	5.0024	1.0034	0.6965
60	49.9920	24.9984	5.0024	1.0344	0.8445
60	74.9880	24.9984	5.0024	1.0653	0.9924
60	99.9840	24.9984	5.0024	1.0963	1.1403
60	124.9800	24.9984	5.0024	1.1272	1.2882
60	24.9960	44.9934	5.0024	1.0124	0.7142
60	49.9920	44.9934	5.0024	1.0448	0.8823
60	74.9880	44.9934	5.0024	1.0773	1.0504
60	99.9840	44.9934	5.0024	1.1097	1.2184
60	124.9800	44.9934	5.0024	1.1421	1.3865

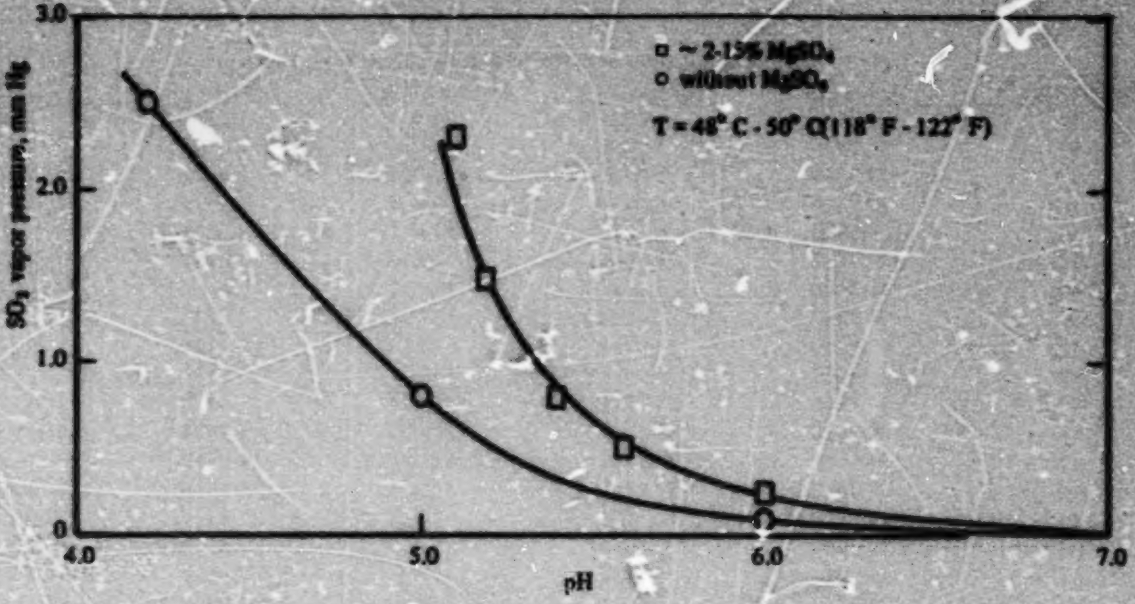

Figure 15. Effect of MgSO$_4$ and pH on sulfur dioxide vapor pressure over magnesium sulfite slurry (15).

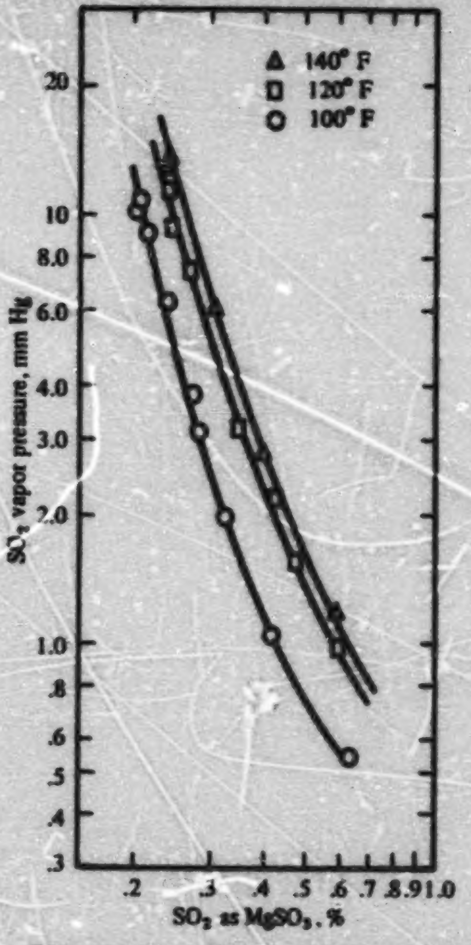

Figure 16. Effect of dissolved MgSO$_3$ on SO$_2$ vapor pressure over MgSO$_3$-Mg(HSO$_3$)$_2$ solutions total SO$_2$ 4.44% (63).

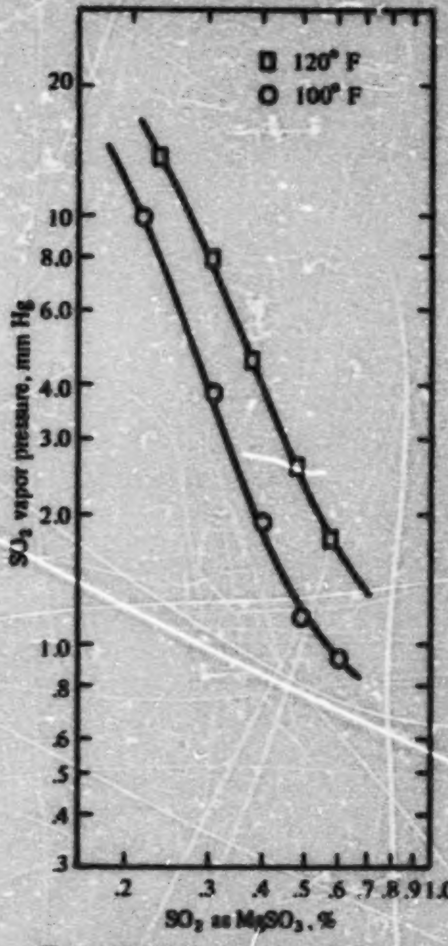

Figure 17. Effect of dissolved MgSO$_3$ on SO$_2$ vapor pressure over MgSO$_3$-Mg(HSO$_3$)$_2$ solutions total SO$_2$ 6.16% (63).

Because of the high concentration of MgO and water at the particulate surface, formation of $Mg(OH)_2$ should be much more rapid than its subsequent dissolution; therefore, Smithson and Bakhshi believe the second reaction is rate controlling.

The dissolution rate of $Mg(OH)_2$ and, hence, reactivity will be proportional to surface area which in turn depends on time and temperature of calcination of MgO. Calcination temperatures for optimum reactivity and surface area may vary from 400 to 1000° C, depending on the magnesium compound being decomposed. MgO calcined at 1200° C is called "hard burned" while that calcined above 1600° C is called "dead burned." Both "hard burned" and "dead burned" magnesium oxide may be quite unreactive.

As a result of pilot plant work, Downs and Kubasco (27) and Gaulo researchers feel that preslaking MgO is not necessary. This could, however, depend on the properties or source of the raw material. Pilot plant tests carried out by Chemico-Basic at Cleveland Electrical Illuminating Company show that recycle MgO was as reactive as virgin MgO (80). From this limited information, it appears that the reactivity of recycled MgO is sufficiently high so that no preslaking is necessary. This could change if MgO were calcined for prolonged periods above 1200° C.

pH—Both Pisaev (71) and Semishin *et al* (78) have measured the pH of magnesium bisulfite solutions saturated with magnesium sulfite in the presence of magnesium sulfate. The data of Semishin *et al* was chosen for detailed mathematical treatment because it covers solution pH above 7.0, which is desirable in the magnesia slurry process. However, with the exception of one datum point, the agreement between the two data sets is good.

Semishin's data cover the pH range 3.82 to 8.70 between 25 and 70° C with 0 and 10% magnesium sulfate. The data were fitted to the equation:

$$\text{pH} = b_0 + b_1\,(S/C) + b_2\,(S/C)^2 + b_3\,(S/C)^3 \qquad (20)$$

where S/C is the molar ratio of sulfur dioxide to active magnesia and b_0, b_1, b_2, and b_3 are constants. When the data are represented in this form, temperature is not statistically significant and does not explicitly appear in the equation. It is important to understand that magnesium concentration (C in equation 20) will vary with temperature for $MgSO_3$-$Mg(HSO_3)_2$ slurries; therefore, temperature dependence is indirectly included in the equation. The equation does not reflect temperature variation in $MgSO_3$-$Mg(HSO_3)_2$ solutions where magnesium concentration is not fixed; e.g., clear liquor solutions which are unsaturated with respect to $MgSO_3$.

The standard error of equation 20 at 0% $MgSO_4$ was 0.1 pH unit and 0.4 pH unit at 10% $MgSO_4$. When plotted in figure 18, the data clearly show the effect of dissolved $MgSO_4$ on pH. The effect is particularly significant at the higher S/C ratios (lower pH) which will occur in the clear liquor process.

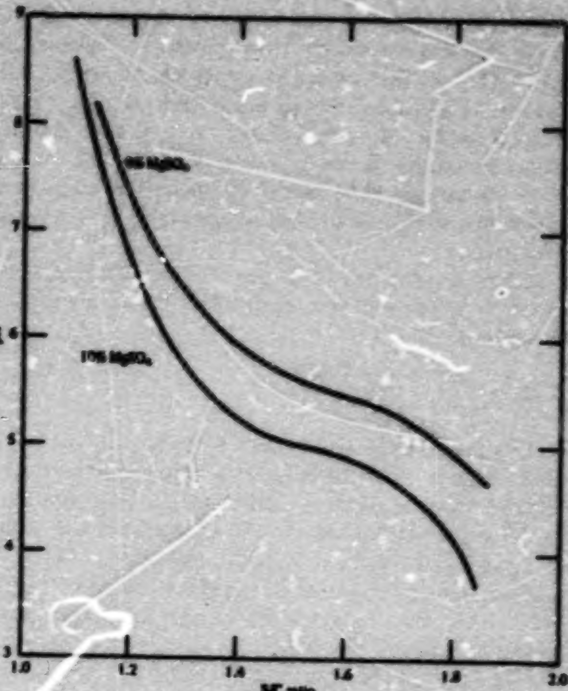

Figure 18. Effect of $MgSO_4$ content and $Mg(HSO_3)_2$/$MgSO_3$ ratio on solution pH (78).

Chertkov reports 8.3 as the pH of a saturated solution of pure magnesium sulfite at 50° C, while Jordan (50) reports 8.8 as the pH of saturated $MgSO_3$ solution at 25° C.

Oxidation of magnesium sulfite to magnesium sulfate—Because thermal decomposition of magnesium sulfate requires higher temperature and more energy than decomposition of magnesium sulfite, it is advantageous to retard sulfite oxidation throughout the process. Johnstone (47) showed that little sulfur dioxide is oxidized in the gas phase by flue gas. Therefore, sulfite oxidation will be primarily dependent on scrubbing solution characteristics such as temperature, sulfite and bisulfite concentration, pH, and oxygen mass transfer rate.

Downs and Kubasco (27) indicate that most of the magnesium sulfate formed in mobile bed or venturi scrubbers results from sulfite oxidation by oxygen absorbed from flue gas rather than NO_x, SO_3, or oxygen in makeup water. The rate controlling step may be either oxygen diffusion rate across the liquid film, or catalytic oxidation of sulfite to sulfate. Downs and Kubasco, as well as Linek and Mayrhoferova (58), feel that catalytic oxidation is rate limiting.

As shown in figure 19, Chertkov (17), using packed tower scrubbers with $MgSO_3$ as the absorbent, found that increasing salt concentration, primarily magnesium sulfate, drastically reduced oxygen mass transfer coefficients and presumably sulfite oxidation rates. He attributes this decrease to increased solution density and viscosity. Operation at higher pH also reduced oxygen mass transfer coefficients from 46 g/m²–hr atm at pH 5.5-5.7 to 19.5 g/m²–hr atm at pH 6.9. Figure 20 shows that magnesium sulfite oxidation is more rapid at low pH (5.5-5.7) than at high pH (6.9).

Chertkov (18) has developed the following empirical equation to relate oxygen uptake to solution and process parameters.

$$G_{O_2} = \frac{0.8\,Q^{0.7}\ a\ (S/C)^6}{\gamma\rho} \qquad (21)$$

Q represents the liquid rate in M³/M²-hr, S/C is the molar ratio of dissolved sulfur dioxide to magnesium, a is a dimensionless temperature coefficient equal to t/50 where t is the average centigrade solution temperature, and γ and ρ are, respectively, slurry viscosity and density. G_{O_2} is in g/M²-hr atm. Although strictly applicable to the pH range 4.0-6.2, the equation gives a general idea of trends in sulfite oxidation above pH 6.2.

The equation predicts moderate increases in oxidation rate with increasing temperature and decreasing slurry viscosity and density; but variations in composition of the sulfite-bisulfite solution, represented by S/C, will have a decisive influence on oxidation rate, particularly in moderately acid solutions. With decreasing acidity, the S/C ratio approaches 1.0 and the influence of S/C becomes less pronounced.

Chertkov points out that laboratory studies of oxidation kinetics of sulfite-bisulfite are, in general, not confirmed under pilot plant conditions. Ample evidence of this exists in the magnesia system. For example, Winston *et al* (97) claim that, in the presence of iron catalysts, maximum oxidation rate occurs at pH 7, which corresponds to a S/C ratio of 1.23. Winston also claims that in the absence of catalyst the oxidation rate is almost independent of sulfite or bisulfite concentration (S/C ratio). It is known that iron will promote oxidation (47) but the claim that oxidation rate is independent of solution composition is not substantiated.

Kim (55), working with the analogous calcium system at constant total sulfur, finds that oxidation rate decreases with decreasing pH and, thus, would appear to disagree with Chertkov. Kim's data are found in figure 21.

As shown in Schroeter's (76) monograph, Able, on the basis of a plausible free radical reaction mechanism, developed the following rate equation.

$$\frac{-d[SO_3^{=}]}{dt} = \frac{g[HSO_3^-]}{\sqrt{H+}} \qquad (22)$$

Oxidation rate will then depend on the ratio $[HSO_3^-]/\sqrt{H^+}$.

Results of a detailed study by Potts *et al* (73) have resolved some of the apparent discrepancies between laboratory and pilot plant studies. Using extended Debey-Huckel equations to calculate hydrogen and bisulfite ion activities in the system $CaO\text{-}SO_2\text{-}H_2O$, Potts *et al* show that the ratio $[HSO_3^-]/\sqrt{H^+}$, and hence oxidation rate, may either decrease or increase with pH changes depending on whether the system is saturated or unsaturated with respect to $CaSO_3\cdot\frac{1}{2}H_2O$. Decreasing pH strongly inhibits oxidation rate in unsaturated solutions, but in saturated slurries, oxidation rate increases with declining pH. Similar results might be expected for the analogous $MgO\text{-}SO_2\text{-}H_2O$ system.

Thus, the apparent disagreement between Chertkov and Kim may be due to the use of different experimental conditions. Oxidation rate should increase with decreasing pH in MgO slurries as Chertkov found. But in the clear liquor process with unsaturated solutions, decreasing pH should inhibit the oxidation rate.

Air oxidation of sulfite is a light-sensitive chain reaction (62) involving free radicals and, like many such reactions, is accelerated by heavy metal cations and inhibited by free radical scavengers. Inhibitors include phenols, hydroquinone, numerous alphatic alcohols, ketones, and esters. As Johnstone (48) pointed out, flue gases contain such inhibitors and, thus, will retard sulfite oxidation. Chertkov (17) shows that as little as 0.001% p-aminophenol in the scrubber solution can reduce the sulfite oxidation rate by one-half.

Manvelyan *et al* (62) note that traces of nitrogen oxides reduce the inhibitory action of p-phenylenediamine and p-aminophenol. But, because Manvelyan does not state the nitrogen oxide concentration used, it is difficult to estimate the significance of NO_X.

As early as 1931, Johnstone (48) pointed out that iron and manganese catalyzed sulfite oxidation. In the same publication, he reported that copper ions inhibited sulfite oxidation, but this has not been substantiated. Data by Bottomley and Cullen (7) show the high catalytic activity of manganese and copper ions. Linek and Mayrhoferova (58) report that cobalt also shows strong catalytic activity. Because of corrosion, these transition metal cations might be expected to be present at trace concentration in process solutions. Another source of iron is the presence of fly ash. Downs and Kubasco reported that fly ash accelerated the oxidation of magnesium sulfite in mobile bed and venturi scrubbers. They tentatively attribute the increased oxidation to iron in the fly ash.

Developers of the Grillo process claim that manganese ions significantly increase the efficiency and capacity of magnesium sulfite scrubber solution to absorb SO_2. But in view of the known catalytic activity of manganese, additional sulfite oxidation might be expected.

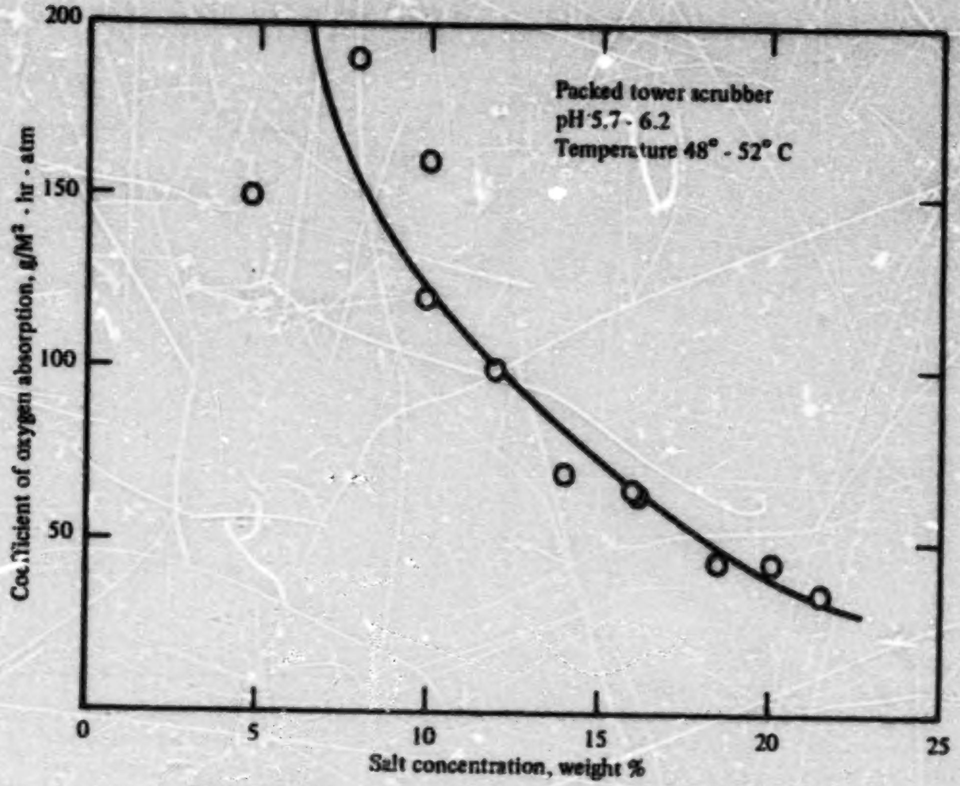

Figure 19. Effect of salt concentration on oxygen absorption (17).

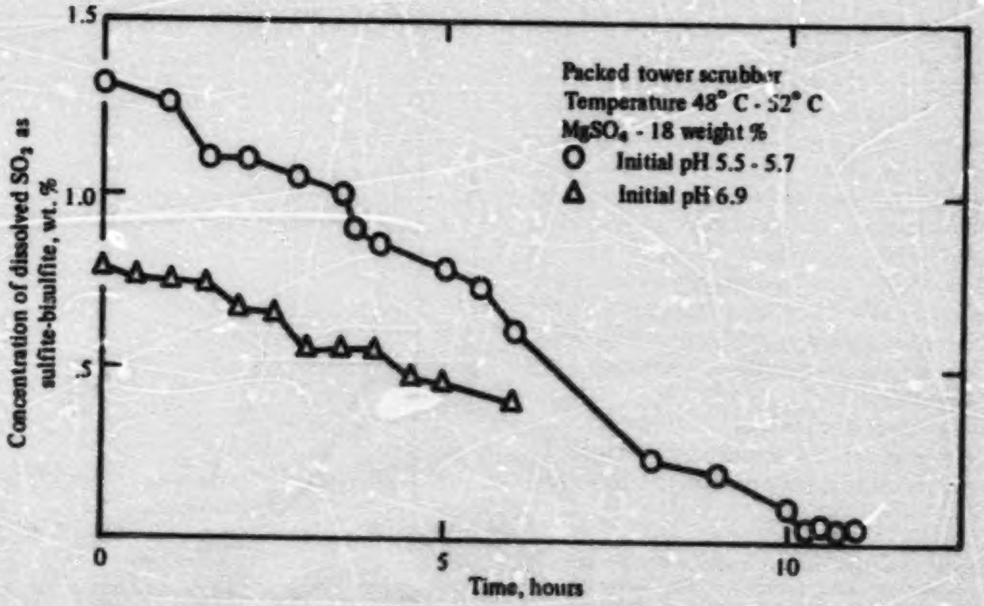

Figure 20. Effect of pH on air oxidation rate in magnesium sulfite-bisulfite solution (17).

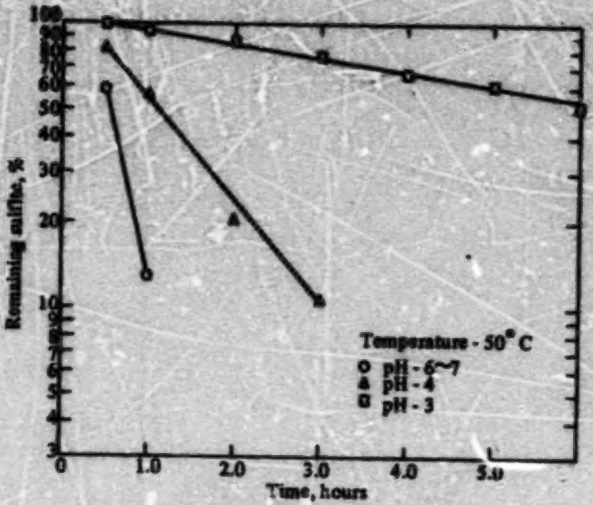

Figure 21. Effect of pH on calcium sulfite oxidation rate (55).

Pinaev (72), in figure 22, shows that surface oxidation of magnesium sulfite crystals is greatly reduced by introduction of 0.001-0.005% p-phenylenediamine into the crystal lattice. This could be an effective means of retarding oxidation when magnesium sulfite crystals are stored or shipped off-site for calcination and regeneration of MgO. Especially during transit, surface oxidation of the crystals could become excessive.

Slurry conversion of $MgSO_3·6H_2O$ to $MgSO_3·3H_2O$—Prior to calcination, magnesium sulfite hydrate should be dehydrated so that the minimum amount of water will be driven off with SO_2 from the calciner. Because less energy is required to dehydrate $MgSO_3·3H_2O$ than $MgSO_3·6H_2O$, the observation (33) that $MgSO_3·6H_2O$ slurry converts to $MgSO_3·3H_2O$ at a reasonably low temperature is quite significant.[1] Because of the difference in crystal size, $MgSO_3·3H_2O$ should be somewhat more difficult to dewater; however, the difference in dewatering probably will not negate the advantage of converting $MgSO_3·6H_2O$ to $MgSO_3·3H_2O$ prior to drying.

Figure 23 shows the effect of temperature and slurry concentration on the conversion rate. The percent degraded material was estimated by petrographic analysis; therefore, the results are somewhat imprecise. Nevertheless, two trends are clearly evident:

1. The rate is temperature sensitive.
2. The conversion rate is significantly increased by increasing the slurry concentration from 10 to 60% $MgSO_3$.

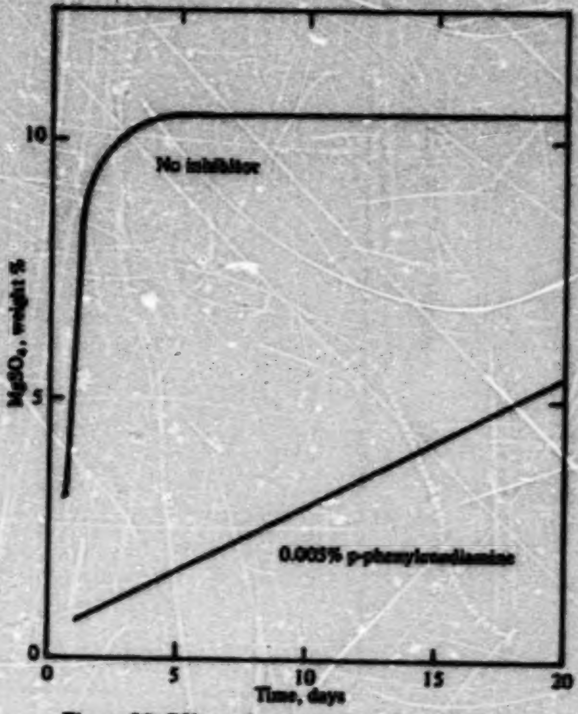

Figure 22. Effect of p-phenylenediamine and time on oxidation of magnesium sulfite crystals exposed to atmosphere (72).

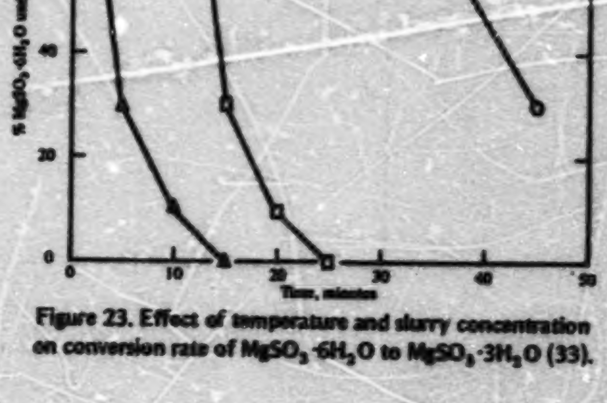

Figure 23. Effect of temperature and slurry concentration on conversion rate of $MgSO_3·6H_2O$ to $MgSO_3·3H_2O$ (33).

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[1] Through private communication it is known that the Babcock and Wilcox Company has done research on this conversion procedure, but their results are yet to be published. Poisakhov and Chertkov (68) have also noted this phase transition.

For rapid conversion, a temperature near 80° C is desirable.

The dehydration product is quoted as degraded material rather than $MgSO_3 \cdot 3H_2O$ because a small amount of unidentified material (<10%), possibly penta or tetrahydrate, is always present with the trihydrate.

Thermal dehydration and calcination of magnesium sulfite—In the proposed magnesia process, magnesium sulfite hydrate crystals are first dewatered by mechanical means and then thermally dehydrated before feeding to a calciner. The dehydration characteristics of magnesium sulfite hydrates were studied by Okabe and Hori (67) using differential thermal analysis, X-ray analysis, and infrared analysis. Although experimental conditions are not clearly described, their results were obtained by heating the samples in a closed tube. The authors claim that the first 3 water molecules of $MgSO_3 \cdot 6H_2O$ are lost in two steps at 60 and 100° C. At 200° C, the last three water molecules are lost to yield amorphous anhydrous $MgSO_3$.

Results of recent dehydration experiments at TVA differ from those of Okabe and Hori, but because the heated samples were not sealed, the differences may be more apparent than real. Using differential thermal analysis, Jordan (51), see figure 24, shows that when laboratory prepared $MgSO_3 \cdot 6H_2O$ is exposed to air and heated, dehydration starts at about 100° C. Commercially available $MgSO_3 \cdot 6H_2O$, containing impurities believed by Jordan to be lower hydrates, also begins dehydration at 100° C, but a second endothermic decomposition begins at 270° C. When laboratory prepared $MgSO_3 \cdot 3H_2O$ was heated in air, dehydration started at 160° C. It is interesting that an exothermic decomposition or phase change occurs between 430 and 470° C, but no such exotherm was observed when $MgSO_3 \cdot 6H_2O$ was heated.

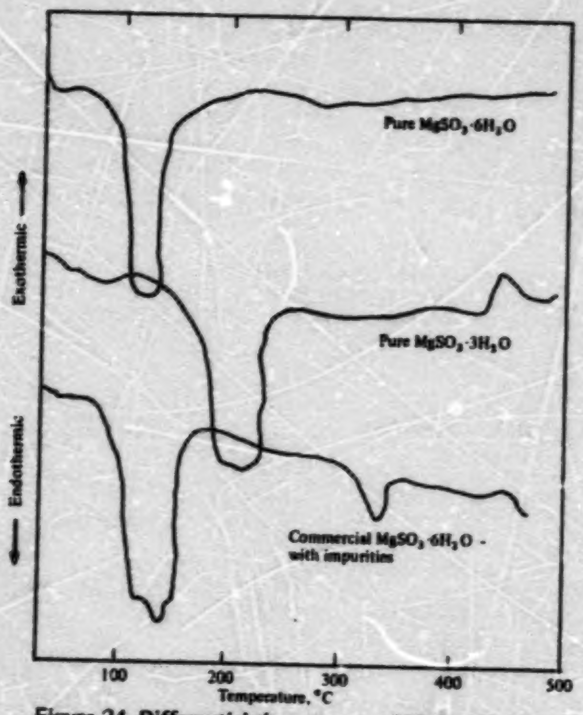

Figure 24. Differential thermogram of $MgSO_3 \cdot 6H_2O$ and $MgSO_3 \cdot 3H_2O$ samples (51).

Results of other TVA work (43) tend to give similar results. After heating $MgSO_3 \cdot 6H_2O$ in a stream of argon for 18 hours at 104° C, Hatfield *et al* showed that 5.67 of the 6 moles of water were lost (95%). The same results were obtained by heating $MgSO_3 \cdot 6H_2O$ in air. X-ray analyses showed only amorphous $MgSO_3$ and a small amount of $MgSO_3 \cdot 6H_2O$ in the dehydration product. There was no evidence for the formation of intermediate lower hydrates. When $MgSO_3 \cdot 3H_2O$ was heated in air for 16 hours at 140° C, 2.3 moles (77%) of the 3 moles of water were lost.

The available evidence suggests that $MgSO_3 \cdot 6H_2O$ is almost completely dehydrated to amorphous $MgSO_3$ in air at 100° C. There is no evidence of partial dehydration to $MgSO_3 \cdot 3H_2O$. In all likelihood, the differences between Okabe-Hori and TVA are due to different experimental conditions used. Partial dehydration of $MgSO_3 \cdot 3H_2O$ can occur at 140° C, but complete, rapid dehydration would require a much higher temperature.

Results of two separate investigations (32, 54) of $MgSO_3$ thermal decomposition between 300 and 600° C are presented in figures 25 and 26. Data from the two sources show reasonable agreement. Although each group of workers proposes different decomposition mechanisms to explain the decomposition products, both groups agree on two points:

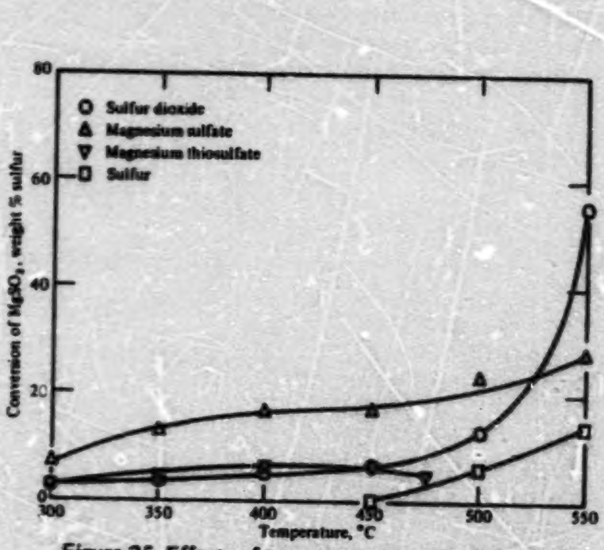

Figure 25. Effects of temperature on nature of $MgSO_3$ decomposition products—one hour heating period (32).

1. The primary sulfur-bearing decomposition products above 500° C are SO_2, $MgSO_4$, and sulfur in decreasing order of occurrence.

2. Even as low as 300° C some decomposition of $MgSO_3$ occurs.

The latter is important because dryer offgas will be sent directly to the stack with no provision for SO_2 recovery. Accidental overheating of the $MgSO_3$ could result in some SO_2 loss and sulfate formation.

Hatfield *et al* (44) have made a rather complete kinetic study of $MgSO_3$ decomposition between 504 and 602° C, and show the order of the decomposition as 3/2. The 3/2 order shows that the decomposition rate per unit volume is higher initially than in the latter stages of decomposition, which suggests that decomposition products interfere with the decomposition reaction. The effects of time and temperature on decomposition are found in figure 27. Extrapolating to higher temperature shows that about eight seconds are required for 99.9% decomposition at 1000° C. This rapid decomposition suggests that thermodynamic equilibrium will be approached at calciner operating conditions and Gibbs Free Energy values may be used to compute the composition of the reaction mass in the calciner.

From standard enthalpy, entropy, and heat capacity data, Whitney, Elias, and May (95) have compiled the necessary thermodynamic information for the calculations. Their data came primarily from the U. S. Bureau of Standards. Logarithms of equilibrium constants for primary reactions are presented in table 3 and figures 28 and 29.

Because free energy is an exact differential, it can be added and subtracted to obtain free energy values for supplementary reactions. Whitney used this technique to calculate the equilibrium constants for the supplementary reactions found in figures 28 and 29.

The formation of magnesium oxide and sulfur dioxide appears to be favorable above 1000° C, but without detailed calculations it is not possible to precisely determine the composition of the solid and gas phases.

To circumvent this problem, Sillen and Andersson (81) have reworked Whitney and May's data into what they call logarithmic equilibria diagrams.[2] These diagrams are in the form of a plot of log P_{O_2} called r0, vs -log P where P represents the partial pressure of any gas of interest over the solid phase. Construction of these diagrams depends on the following assumptions:

$$P_{CO_2} + P_{CO} = 0.15 \text{ atm} \qquad (23)$$

$$P_{H_2O} + P_{H_2} = 0.10 \text{ atm} \qquad (24)$$

$$P_{H_2S} + \tfrac{1}{2}P_{S_2} + P_{SO_2} + P_{SO_3} < 0.01 \text{ atm} \qquad (25)$$

Equations 23 and 24 approximate conditions at the discharge point of the calciner. Since the partial pressure of SO_2 at the discharge point is expected to be about 0.16 atm, equation 25 does not hold; therefore, Sillen and Andersson's treatment should be applied to $MgSO_4$ calcination with caution. While the equilibrium diagrams are of interest in themselves, Sillen and Andersson used them to generate graphs showing conditions under which all sulfur is in the gas phase; i.e., the only solid phase is MgO. In figures 30 and 31, temperature is plotted against the quantity Δ where

$$\Delta = 100\,(P_{O_2} - \tfrac{1}{2}P_{H_2} - \tfrac{1}{2}P_{CO}) \qquad (26)$$

Figure 31 is a vertical expansion of figure 30.

At positive values, Δ is practically the percent O_2 in the gas phase. When Δ is negative, the atmosphere is deficient in oxygen and is reducing. Referring to figures 30 and 31, in the area marked $MgSO_4$, 99% or more of the sulfur is in the form of $MgSO_4$. In the region H_2S-MgO, > 99% of the sulfur is in the form of H_2S, while in the SO_2-MgO area,

Table 3. Log_{10} equilibrium constants vs temperature.

Reaction	500°K	800°K	1200°K	1500°K
$C(s) + \tfrac{1}{2}O_2(g) = CO(g)$	16.3	11.9	9.5	8.5
$C(s) + O_2(g) = CO_2(g)$	41.3	25.8	17.2	13.8
$H_2(g) + \tfrac{1}{2}O_2(g) = H_2O(g)$	22.9	13.3	7.9	5.7
$H_2(g) + \tfrac{1}{2}S_2(g) = H_2S(g)$	6.6	3.2	1.3	0.5
$\tfrac{1}{2}S_2(g) + O_2(g) = SO_2(g)$	33.8	19.8	11.8	8.8
$SO_2(g) + \tfrac{1}{2}O_2(g) = SO_3(g)$	5.3	1.5	-0.5	–
$MgCO_3(s) = MgO(s) + CO_2(g)$	-3.5	1.1	3.4	–
$MgSO_4(s) = MgO(s) + SO_2(g) + \tfrac{1}{2}O_2(g)$	-25.1	-10.3	-2.3	0.8
$MgS(s) + 2O_2(g) = MgSO_4(s)$	78.3	41.9	21.9	14.1
$MgS(s) + H_2O(g) = MgO(s) + H_2S(g)$	3.0	1.8	1.2	0.9

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[2] More precise thermodynamic data is now available (46) but this should not significantly affect Sillen and Andersson's conclusions about the gas phase composition in an oxidizing atmosphere.

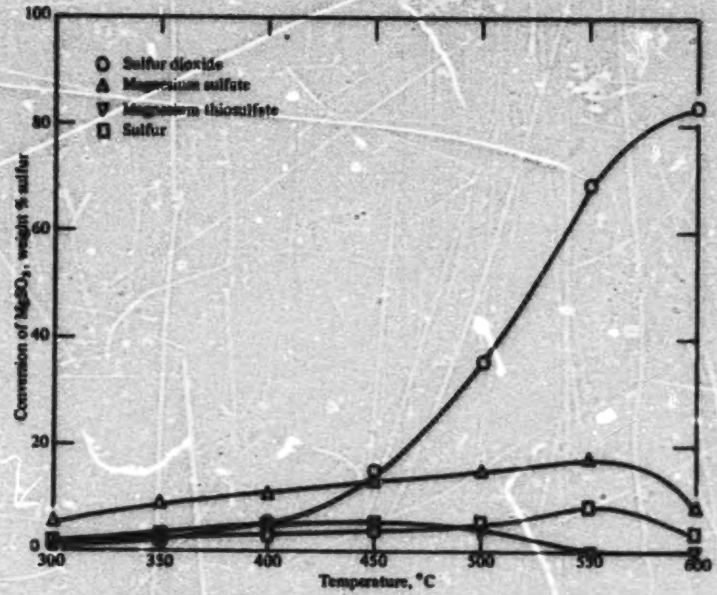

Figure 26. Effect of temperature on nature of $MgSO_3$ decomposition products--15 minutes heating period (54).

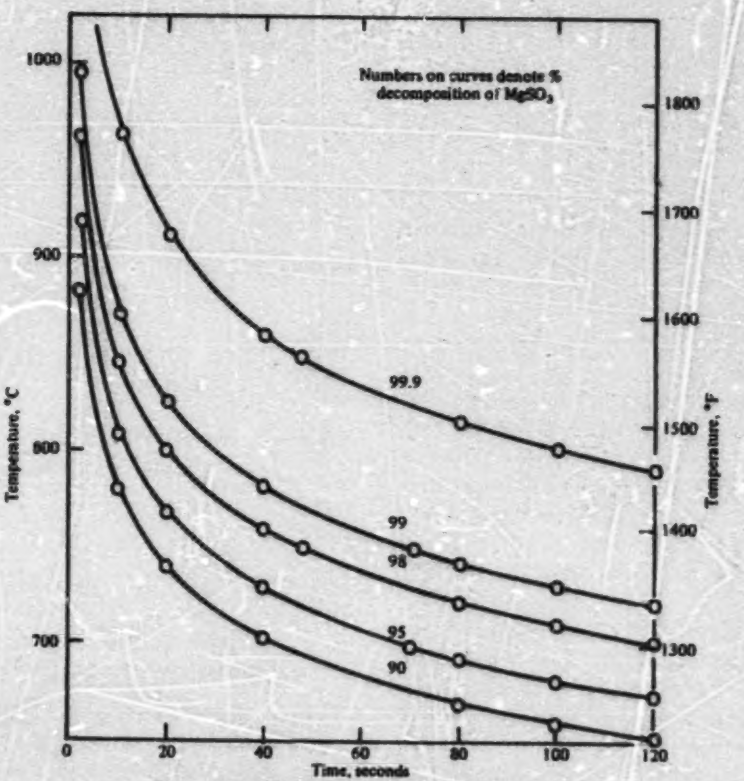

Figure 27. Effect of time and temperature on decomposition of $MgSO_3$ (44).

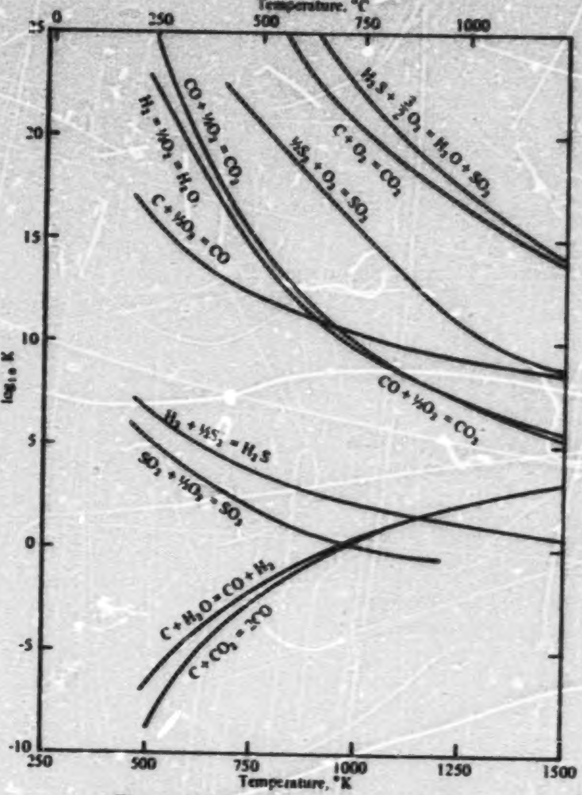

Figure 28. Equilibrium constants for combustion reactions (95).

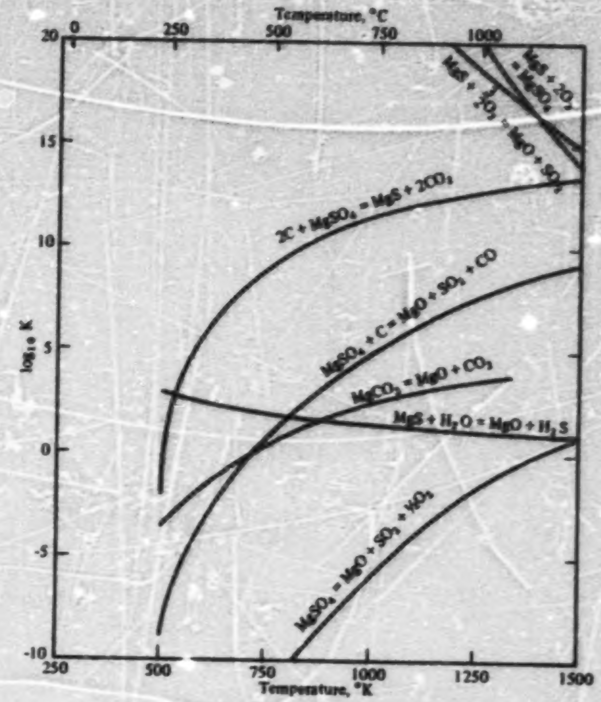

Figure 29. Equilibrium constants for reactions of magnesium compounds (95).

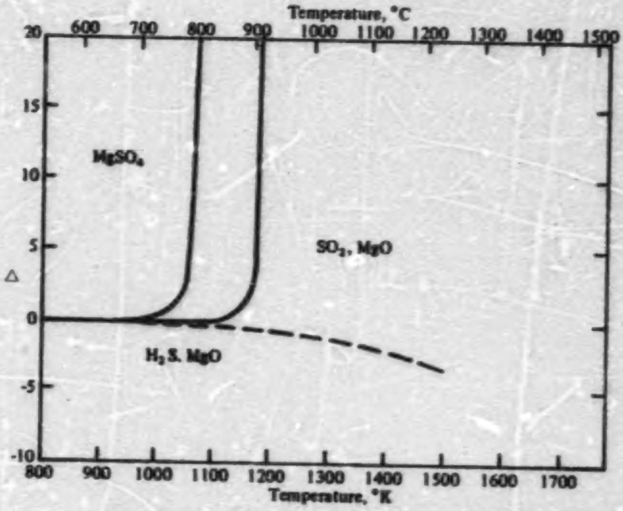

Figure 30. Effect of calcination temperature and atmosphere on formation of product materials (81).

99% of the sulfur is in the form of SO_2. The intermediate region represents conditions where appreciable amounts of both SO_2 and $MgSO_4$ occur. Under conditions covered in figure 30, magnesium sulfide is not a stable phase.

At 1000° C, MgO and SO_2 are the primary reaction products over a wide variation of gas phase compositions. With decreasing temperature, high yields of SO_2 and MgO require a more restricted gas phase composition. Thus, when operating at 900° C, high yields of MgO and SO_2 are possible only when $-0.5 < \Delta < 2.2$. Outside this range either $MgSO_4$ or H_2S occur in unacceptable amounts. Calcination at 800° C requires a reducing atmosphere to prevent formation of $MgSO_4$. This can be accomplished by adding coke to the calciner.

The Grillo developed process uses manganese in the scrubbing system (pyrolusite) to promote absorption of SO_2. As previously noted, manganese may promote sulfite oxidation in the scrubber and, thus, increase the sulfate concentration in the scrubber solids.

Without manganese, a temperature considerably above 800° C (about 1200° C) is required to calcine the magnesium sulfate. At this high temperature there is a danger of hard burning the MgO. But, preliminary data from Grillo-Werke AG, shown in figure 32 (40), indicates that the added manganese catalyzes magnesium sulfate decomposition such that calcination occurs at about 1000° C.

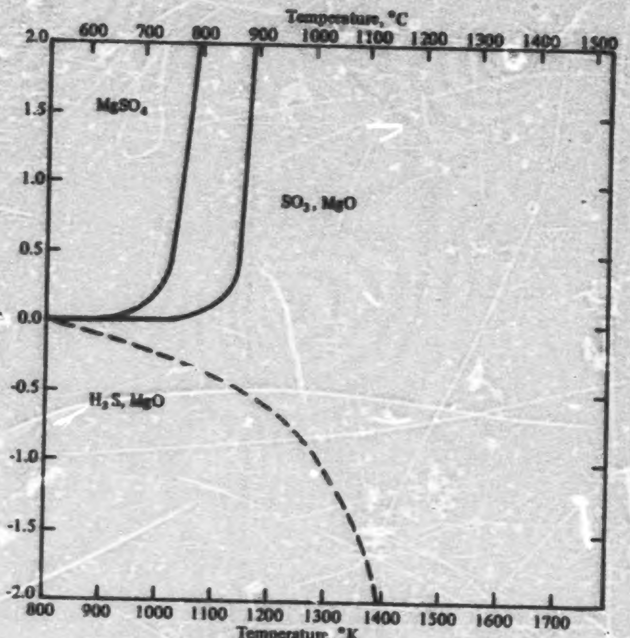

Figure 31. Effect of calcination temperature and atmosphere on formation of product materials (expanded vertical scale) (81).

Kinetics and Mass Transfer

Information on reaction kinetics for the magnesia scrubbing system is limited, but for reasons stated below, information from other systems may be of some help in understanding the magnesia system. Chertkov (15), using an aqueous alkaline absorbent, proposes the following sequence of reactions for scrubbing sulfur dioxide.

$$SO_2\ (g) = SO_2\ (\text{solution}) \tag{27}$$

$$H_2O + SO_2\ (\text{solution}) = HSO_3^- + H^+ \tag{28}$$

$$H^+ + OH^-\ (\text{from basic absorbing solutions}) \rightarrow H_2O \tag{29}$$

$$HSO_3^- + OH^-\ (\text{from basic absorbing solutions}) \rightarrow SO_3^= + H_2O \tag{30}$$

The reaction mechanism is considered to be independent of the source of hydroxide ion; therefore, information from similar alkaline systems may be directly applicable to the magnesium system.

Chertkov assumes that the hydration step, equation 28 is the slowest step, and at elevated SO_2 concentrations, it will become rate limiting. However, if ammonia, sodium hydroxide, or sodium carbonate are the absorbents, equation 28 becomes rate limiting only when the SO_2 concentration in the gas phase exceeds 3.5% (19).

Reported mass transfer coefficients vary widely and are difficult to compare because of different experimental conditions, scrubber type, gas velocity, liquid intensity, temperature, and solution composition. Based on data obtained from a packed absorber and magnesium sulfite-bisulfite slurry (50° C, pH 6.2) as the absorbent, Chertkov reports that sulfur dioxide mass transfer coefficients are directly proportional to gas flow rates up to at least 5.9 ft/sec. The relationship between mass transfer coefficient and gas velocity is found in figure 33.

As shown in figure 34, changes in liquid mass rate also have a noticeable effect upon the mass transfer process. With constant gas flow rate, Chertkov reports the mass transfer coefficient, K, to be proportional to liquid intensity raised to the 0.4 power.

In the pH range tested, 6.1 to 6.4, liquid film resistance was not important, but Chertkov states that, with lower pH, liquid film resistance will be more significant because of reduced SO_2 solubility and increased viscosity. The increased liquid film resistance leads to a decrease in mass transfer rate and, thus, would tend to favor the slurry process (high pH) over a clear liquor process.

Using clear liquor solutions, Markant *et al* (63) have measured mass transfer coefficients in venturi scrubbers at rather high gas velocities and under a wide variety of conditions. Their data covered much higher gas velocities than did Chertkov's, 30-100 ft/sec vs 1-6 ft/sec. The results (figure 35) show the increased mass transfer that occurs with higher gas mass flow rate.

While no information on the effect of temperature on SO_2 transfer rates into $MgSO_3$ slurries is available, results from ammonia, sodium carbonate, and sodium hydroxide scrubbing shed light on the magnesia system (20). As shown in figure 36, the mass transfer coefficient, K, falls only slightly with increasing temperature when using NaOH or Na_2CO_3 scrubbing solution, but the decrease in K is quite pronounced in the ammonium sulfite-bisulfite system. Chertkov attributes the behavior difference to the rapid increase in SO_2 vapor pressure with temperature in the ammonium bisulfite system.

Thus, if the pH of a magnesia scrubbing slurry remains above 7.0 where SO_2 vapor pressure is very low, the adverse influence of increased temperature on K will be slight. But, in an acid-sulfite solution (lower pH), SO_2 vapor pressure increases rapidly with temperature (63); therefore, significant reduction in K will occur.

Using venturi scrubbers and magnesium sulfite-bisulfite solution (not slurry), Markant *et al* (63) find that SO_2 absorption efficiency decreases by about 10% between 110° F (44° C) and 170° F (77° C) at 0.812% $MgSO_3$-5.09% $Mg(HSO_3)_2$. They also show that the decreased scrubbing efficiency can be offset by increasing the $MgSO_3$

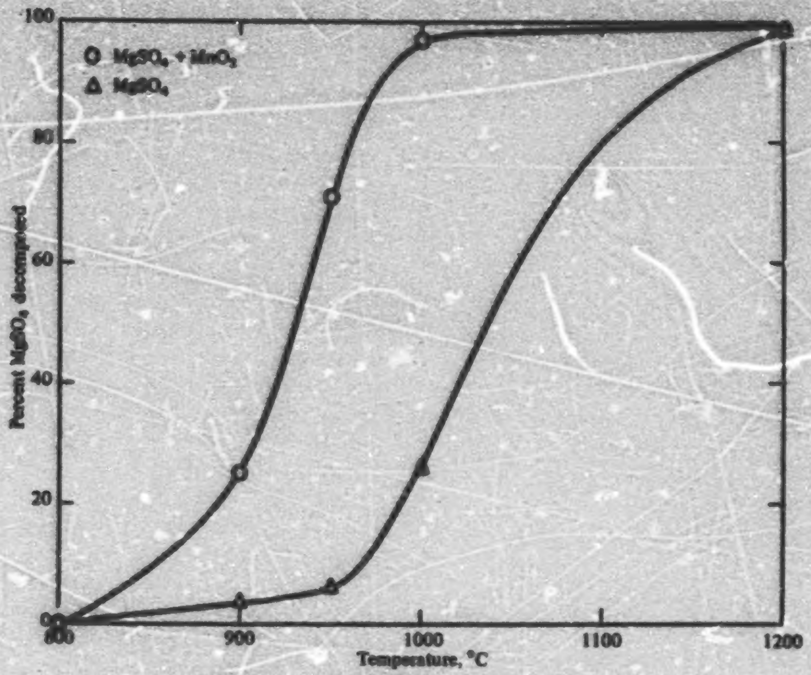

Figure 32. Effect of manganese on the rate of magnesium sulfate decomposition (40).

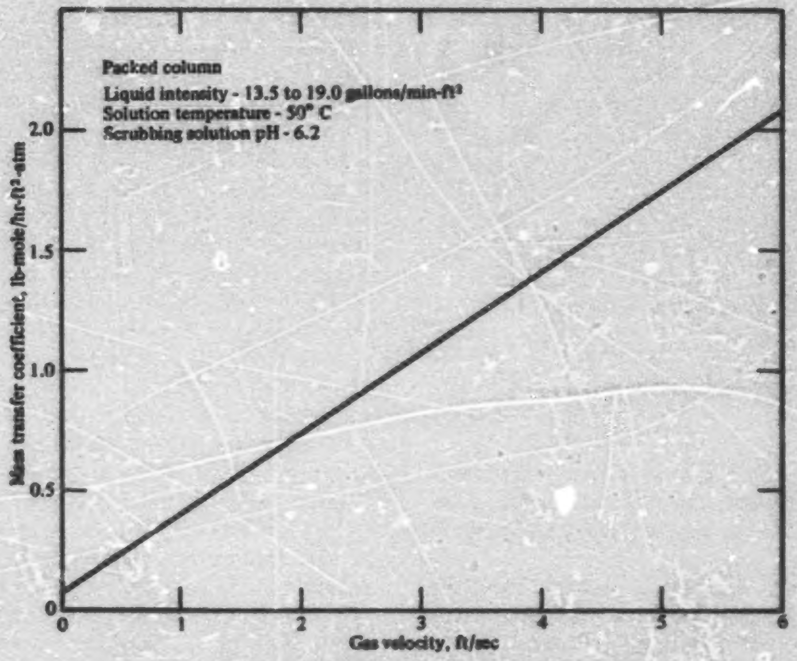

Figure 33. Effect of gas velocity on mass transfer coefficient (15).

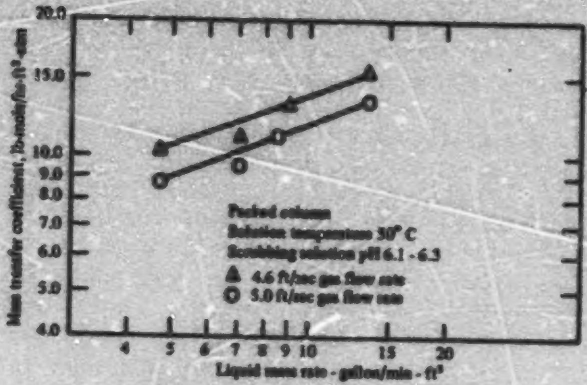

Figure 34. Effect of liquid mass rate on mass transfer coefficient (15).

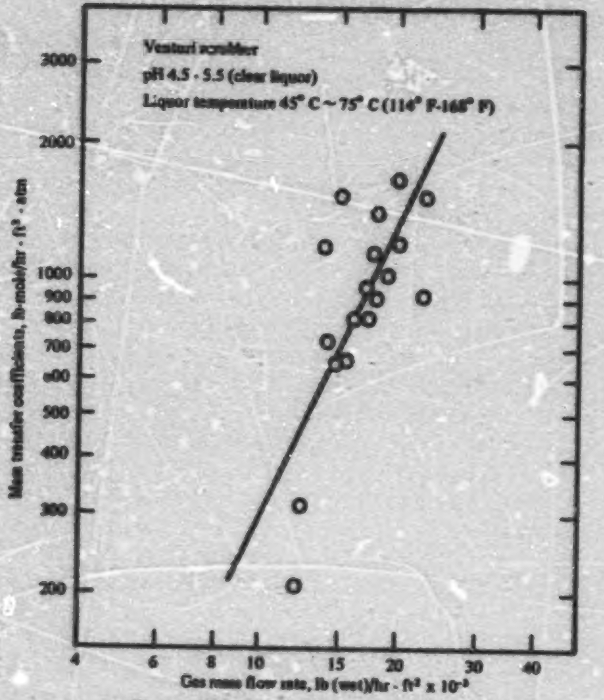

Figure 35. Effect of gas mass flow rate on mass transfer coefficient (63).

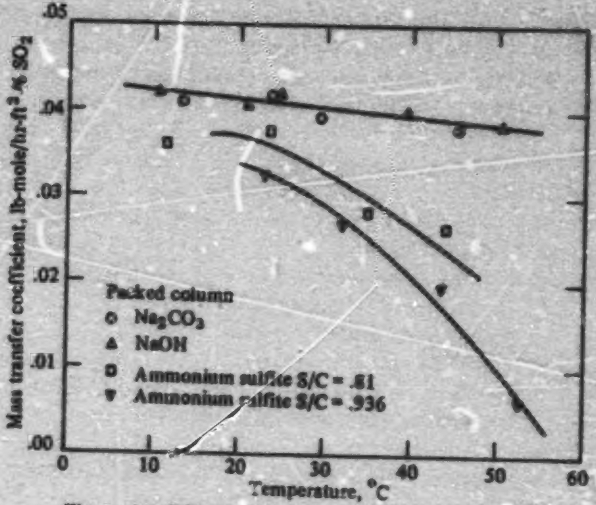

Figure 36. Effect of temperature on mass transfer coefficient in absorption of SO_2 by various solutions (20).

concentration to 1.16%. Because $MgSO_3$ concentration increases with temperature in a slurry system, it is doubtful if any significant decrease in SO_2 absorption will occur with moderate temperature changes.

Formation of Crystalline Deposits (Scaling)

Because crystalline deposits of hydrated magnesium sulfites might form when saturated solutions or slurries are used to scrub SO_2, there is naturally some concern about potential scaling problems. While several theories are advanced to explain crystal growth, there is general agreement that, for a crystal to grow, it must overcome two resistances: diffusion of solute molecules or ions to the crystal face and incorporation of the solute into the crystal. Diffusional resistance depends on solution properties and movement of solution through the crystal. Incorporation of solute into the crystal depends on the properties of the crystal and crystal temperature.

Studies made with $KAlSO_4 \cdot 12H_2O$ (6), $CuSO_4 \cdot 5H_2O$ (65), and $MgSO_4 \cdot 7H_2O$ (22) show that crystal growth rate initially increases rapidly with solution velocity past the crystal face, but levels off at higher solution velocities. The $KAlSO_4 \cdot 12H_2O$ growth rate becomes independent of solution velocity above 1.3 in./sec. Magnesium sulfate heptahydrate growth rate levels off at about 9 in./sec. For $CuSO_4 \cdot 5H_2O$, the increase in growth rate becomes negligible above a solution velocity of 2 in./sec.

Clontz *et al* (22) show that the rate at which $MgSO_4 \cdot 7H_2O$ was incorporated into the crystal increased with degree of supersaturation and temperature. Botsaris and Denk (6) also show that growth rate increases with degree of supersaturation.

In general, at low solution velocity, crystal growth rate depends on solution velocity, but at higher velocity, crystal growth rate is independent of solution velocity. This "breakpoint" occurs below 1 ft/sec. Crystal growth rate, particularly at higher solution velocities such as will occur in pipes, increases with crystal temperature and degree of supersaturation.

For the process under consideration, $MgSO_3 \cdot 6H_2O$ crystal growth may be expected at points of high solution velocity and turbulence where solutions are supersaturated with $MgSO_3$ or at wet-dry interfaces of scrubbers. In a pilot plant study, Downs and Kubasco (27) found magnesium sulfite deposits most prevalent at points of extreme turbulence such as sump suction and discharge, and along threaded sections of plastic pipe. The deposit appeared as a "hard, resilient, plate-like deposit" tightly bonded to the metal surfaces. Similar deposits of $CaSO_4 \cdot 2H_2O$ and $CaSO_3 \cdot ½H_2O$ occur in the limestone system.

Downs and Kubasco note several factors which influence deposit formation:

1. Systematic shifting of sulfite slurry concentration.
2. Availability of precipitation surface area.
3. Nature of the surface material.
4. Fluid flow environment.

Systematic shifting of $MgSO_3$ slurry concentration may occur by chemical reaction or temperature changes and, in either case, probably changes the degree of supersaturation.

They propose the following reactions for the gas-liquid scrubber:

$$SO_2 + OH^- \rightarrow HSO_3^- \tag{31}$$

$$SO_3^= + H_2O \rightarrow HSO_3^- + OH^- \tag{32}$$

$$MgSO_3 \cdot 6H_2O \rightarrow Mg^{++} + SO_3^= + 6H_2O \tag{33}$$

The net equation is

$$MgSO_3 \cdot 6H_2O + SO_2 \rightarrow Mg^{++} + 2HSO_3^- + 5H_2O \tag{34}$$

thus, relatively insoluble $MgSO_3$ actually dissolves to the more soluble $Mg(HSO_3)_2$ in the gas-liquid scrubber. In the sump, where bisulfite is partially neutralized with MgO, these reactions occur:

$$HSO_3^- + OH^- \rightarrow SO_3^= + H_2O \tag{35}$$

$$6H_2O + SO_3^= + Mg^{++} \rightarrow MgSO_3 \cdot 6H_2O \downarrow \tag{36}$$

The last reaction is the mechanism by which crystal growth proceeds. They support this mechanism with the following observations:

1. No deposits form in the gas-liquid contact zone where $MgSO_3$ is actively dissolving.
2. Deposition is most severe in the sump and piping when the system is acid and MgO is directly added to the sump.
3. Deposition was substantially reduced by changing the MgO makeup point from the sump to the gas-liquid contact zone.

To insure rapid reaction, they preslaked the MgO; but, in view of its reactivity, preslaking does not appear to be necessary.

Temperature cycling may occur when there is a temperature drop between the inside pipe wall and bulk liquid or in the bulk slurry due to heating by flue gas and cooling by makeup slurry and water. In either case, solutions may become supersaturated and crystal growth occur.

Downs and Kubasco find fly ash very effectively reduces the tendency to form solids. They attribute this to additional suspended surface created by the finely divided fly ash and the abrasive or scouring action of fly ash.

The ability of a solid to adhere to a solid surface depends on the attractive force between the surface and the deposit. Downs and Kubasco relate the attractive force to the wetability of the surface by sulfite solutions. Surfaces not wet by liquids have little affinity for the liquid; therefore, the contact angle between liquid and surface is high; i.e., the liquid forms beads on the solid surface. When the affinity between liquid and solid surface is high, wetability is high and contact angles are lower.

The polyvinylidene chloride pipe material used in their tests has a surface with a large contact angle; therefore, in zones where deposit formation is a problem, it is a better material of construction than steel or brass which has a lower contact angle.

In summary, the following action should be taken to reduce deposit formation.

1. Reduce the degree of $MgSO_3$ supersaturation and precipitation by adding MgO as close as possible to the SO_2 scrubber and where possible maintain constant temperature. Avoid dramatic pH changes which result in a shift from acid to base or base to acid.
2. Allow some fly ash into the system.
3. Choose the proper material of construction where supersaturation and high solution flow rate or turbulence are unavoidable.

In addition, the use of a high solids concentration in the scrubbing slurry will provide additional deposition sites; therefore, reduce scale formation. The solids concentration, of course, is limited by pumping and erosion difficulties.

Process Contaminants

Soluble impurity buildup in particulate scrubber—For those particulate removal systems which must operate with closed loop scrubbing liquor, consideration should be given to contaminant buildup. Usually recycle water from the ash pond is used to scrub fly ash from the flue gas with the resulting slurry pumped back to the pond. Makeup water is added only to compensate for humidification losses.

Two sources of soluble impurities should be considered:

1. Makeup water.
2. Soluble impurities leached from the fly ash.

Both will be highly variable and little is known of the leaching characteristics of fly ash. Presented in table 4 are typical limits of fly ash analysis of United States bituminous coals (77). The sulfur trioxide reported in the

Table 4. Typical limits of ash analysis of United States bituminous coals (77).

Constituent	%
Silica, SiO_3	20-60
Alumina, Al_2O_3	10-35
Ferric oxide, Fe_2O_3	5-35
Calcium oxide, CaO	1-20
Magnesium oxide, MgO	0.3-4
Titanium dioxide, TiO_2	0.5-2.5
Alkalies, $Na_2O + K_2O$	1-4
Sulfur trioxide, SO_3	0.1-12

coal ash analysis represents sulfur retained in the ash and consists principally of $CaSO_4$.

Because of the paucity of laboratory data on fly ash leaching, the relative importance of leaching vs makeup water to the impurity buildup problem was estimated using data from a TVA power plant. Recognizing variability in fly ash leaching and makeup water composition, the information below is not universally applicable.

Table 5 presents average Cl^-, $SO_4^=$, and $CaCO_3$ analysis of makeup water. The calculated impurity input is based on 0.266 l. of makeup water per pound of coal burned.

Table 6 shows analysis of ash pond water. It can be assumed that the dissolved minerals in the water are derived from both ash leaching and makeup water. The impurity input in g/lb coal burned is estimated from analysis of water leaving the pond and the quantity of pond water per pound of coal burned which is about 3.69 l.

A comparison of table 5 with table 6 shows that the fly ash supplies most of the soluble impurities in the ash pond water.

Based on the pond water analysis and a pond volume of 150,000,000 gallons, the level of impurity buildup during 1 year can be calculated for a 500-mw unit burning 375,000 pounds of coal per hour. Results are found in column 4 of table 6.

The increase of $CaCO_3$ and $SO_4^=$ over an operating time of 1 year is enough to precipitate $CaSO_4$ and perhaps $CaCO_3$. Not considered in the calculation is the influence of SO_2 and SO_3 in the flue gas. The pH of the pond water at the power plant from which the data were taken is 10.1. In such case, some SO_2 and SO_3 will also be scrubbed out in the particulate scrubber. The SO_3, on the order of 0.001 volume %, will immediately be converted to sulfate. In the absence of laboratory or pilot plant data, the effect of the SO_2 on impurity buildup is conjectural. The SO_2 will lower the pH of the pond water and probably increase the rate of leaching. At the same time, the decreased pH may be enough to prevent precipitation of $CaCO_3$. Because there is excess O_2 in the flue gas, some of the absorbed SO_2 may be oxidized either in the scrubber or in the ash pond, causing the sulfate concentration to increase. The presence of dissolved iron and manganese will accelerate the oxidation rate both in the scrubber and in the pond.

Table 5. Makeup water analysis.

Impurity	Concentration, g/l	Impurity input, g/lb coal burned
$CaCO_3$	0.072	0.019
$SO_4^=$	0.015	0.0040
Cl^-	0.010	0.0027

Table 6. Analysis of ash pond water.

Impurity	Concentration, g/l	Impurity input, g/lb coal burned	Impurity input level in 500-mw plant, g/l--year
$CaCO_3$	0.098	0.36	1.7
$SO_4^=$	0.090	0.32	1.5
Cl^-	0.015	0.054	0.26
Ca^{++}	0.035	0.13	0.60
Mg^{++}	0.0025	0.0090	.042
Fe^{+++}	0.0028	0.010	.046
Mn^{++}	0.0003	0.001	.0046
Total dissolved solids	0.280	1.03	4.6

The decreased pH and increased $SO_4^=$ will tend to favor $CaSO_4$ precipitation and prevent $CaCO_3$ precipitation. Unless steps are taken to control the calcium and sulfate level, $CaSO_4$ scaling could occur in the recycle line and the scrubber system. Increased chloride ion buildup, particularly at low pH, could also increase corrosion rates.

Impurity buildup could be controlled by bleeding off a small stream from the pond recycle at a rate, which compensates for impurity input. At least three methods of treating the bleed stream are available: ion exchange, storage in a deadend pond with reliance on solar evaporation to maintain pond volume, or crystallization by steam evaporation with solid disposal. Ion exchange is perhaps the most expensive treatment method. In dry climates with high solar evaporation rates, storage in deadend ponds should be possible. In portions of eastern United States with high rainfall, the bleed stream would have to be concentrated by evaporation before being sent to a deadend storage pond.

Soluble impurity buildup in the SO_2 scrubbing system – With regeneration and recycle of MgO, the sulfur dioxide scrubbing system also will operate closed loop, and therefore, will be subject to buildup of impurities which would result in scaling and corrosion problems. The estimated system losses of water and magnesium oxide are 0.075 lb water/lb coal burned and 8.11×10^{-4} lb MgO/lb coal burned. These losses will be replaced by fresh makeup water and virgin MgO which are both sources of contaminants.

In addition sulfite ion oxidation to soluble $MgSO_4$ will occur, but there is little information currently available to predict the effect of long-term buildup of $MgSO_4$ in continuously operated, closed cycle SO_2 scrubbers.

Chertkov (17) has measured magnesium sulfate increase in a packed tower scrubber system. His results, given in figure 37, show that magnesium sulfate concentration rapidly increased to about 13%. Beyond this, the rate of increase fell to a very low level. However, the duration of the run was only 2.5 days; hence, it is not known if the oxidation rate will be reduced to zero or what the terminal magnesium sulfate concentration will be. If the steady state oxidation rate is not zero, provision must be made for magnesium sulfate removal. Of course when the $MgSO_4$ solubility limit is reached, $MgSO_4 \cdot 7H_2O$ will be removed with $MgSO_3 \cdot 6H_2O$ crystals, but this will not occur until the $MgSO_4$ concentration exceeds 33 weight %. It is possible that enough $MgSO_4$ will be occluded in the $MgSO_3$ crystals to prevent this high $MgSO_4$ concentration, but a minimum steady state concentration of at least 10 to 15 weight % should be expected. If the temperature of the $MgSO_3 \cdot 6H_2O$ slurry is raised to convert the crystals to $MgSO_3 \cdot 3H_2O$, which requires reduced dryer heat, the occluded $MgSO_4$ will be solubilized and returned with mother liquor to the scrubber system.

The concentration range and input rates of some expected impurities in commercially available magnesium oxide are presented in table 7. Impurity input is based on a 500-mw plant using 8.11×10^{-4} lb of MgO/lb coal burned.

The impurity concentration and input rate from one source of makeup water is found in table 8. Input rates are based on a makeup water addition of 0.075 lb of water/lb coal burned.

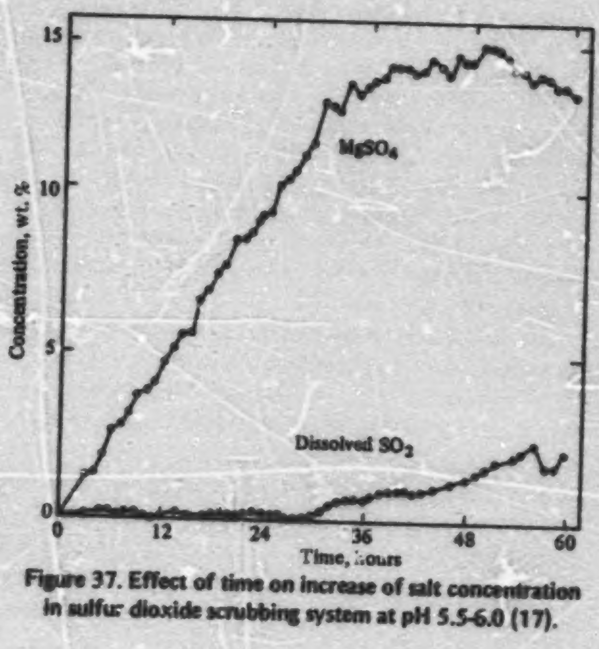

Figure 37. Effect of time on increase of salt concentration in sulfur dioxide scrubbing system at pH 5.5-6.0 (17).

Table 7. Impurities of magnesium oxide.

Impurity	Concentration, wt/%	Impurity input x 10^6 g/lb coal burned
Silica, SiO_2	0.2-7.0	0.16-5.6
Ferric oxide, Fe_2O_3	0.005-1.25	0.004-1.0
Alumina, Al_2O_3	0.04-1.25	0.03-1.02
Chloride ion, Cl^-	0.00-1.0	0.00-0.81
Sulfate ion, $SO_4^=$	0.00-1.2	0.00-0.97
Calcium oxide, CaO	0.5-6.0	0.4-4.9

Table 8. Concentration and impurity input of makeup water.

Impurity	Concentration, g/l	Impurity input x 10^6 g/lb coal burned
Calcium oxide, CaO	0.040	140
Sulfate ion, $SO_4^=$	0.015	51
Chloride ion, Cl^-	0.010	34

Comparison of table 8 with table 7 shows that, in this case, makeup water will contribute almost all of the nonsulfate impurities to the scrubbing system. Because of this, careful attention should be given to the source and purity of the makeup water.

If the prevalent impurity input rate to a 500-mw plant is assumed to be 0.002 g/lb coal burned and impurity concentration in the scrubbing liquor is not allowed to exceed, say, 3.0 g/l., scrubbing solution must be removed and purged at a rate of 4.2 l./min (1.1 gal/min). Some of these impurities will be lost from the scrubber by entrainment in the offgas, but these losses will be quite small; therefore, a purge treatment will be necessary. An important point to consider is that sending a side stream directly to a deadend pond would be the simplest and probably least expensive purge treatment. Assuming a clarified solution with a soluble $MgSO_3$ concentration of 1.2% and a $MgSO_4$ concentration of 15%, the losses would be 33.6 lb of MgO/hr—30.8 lb as soluble $MgSO_4$ and 2.8 lb as soluble $MgSO_3$.

Magnesium losses could be reduced by concentrating the mother liquor until $MgSO_4$ precipitates. Evaporation should not be allowed to proceed beyond the point where undesirable impurities such as NaCl precipitate with the $MgSO_4$. This procedure alone would not remove insoluble impurities such as silica, ferric oxide, aluminum oxide, and fly ash. A possible complete treatment would involve dissolving $MgSO_3 \cdot 6H_2O$ slurry with a minimum amount of sulfur dioxide, filtering the insoluble impurities, then reprecipitating sulfite with makeup MgO. The resultant crystals would be filtered and returned to the system; the mother liquor would be evaporated to recovery $MgSO_4$ and the supernatant of soluble impurities discarded.

Since almost no data exists at this time on the buildup of impurities in aqueous scrubbing processes for SO_2 control, it is difficult to quantify the magnitude of the problem. Only extended operation of a system will yield enough information to define a complete impurity control method.

Nitrogen Oxide Emission Control

The fixation of nitrogen during high temperature combustion may be represented by the following reaction:

$$N_2 + O_2 \rightarrow 2NO \qquad (37)$$

Other nitrogen oxides can be formed from NO; however, as shown in figure 38, at combustion temperatures exceeding 1000° K, only NO is present in significant amounts. Following ejection of the combustion products to the atmosphere, however, the formation of other nitrogen oxides is more likely although the rate of formation may be rather low. The equilibrium constant for reaction 37 may be represented by the following expression:

$$K_{eq} = \frac{[NO]^2}{[N_2]\,[O_2]} = 21.9e^{-43{,}400}/RT \qquad (38)$$

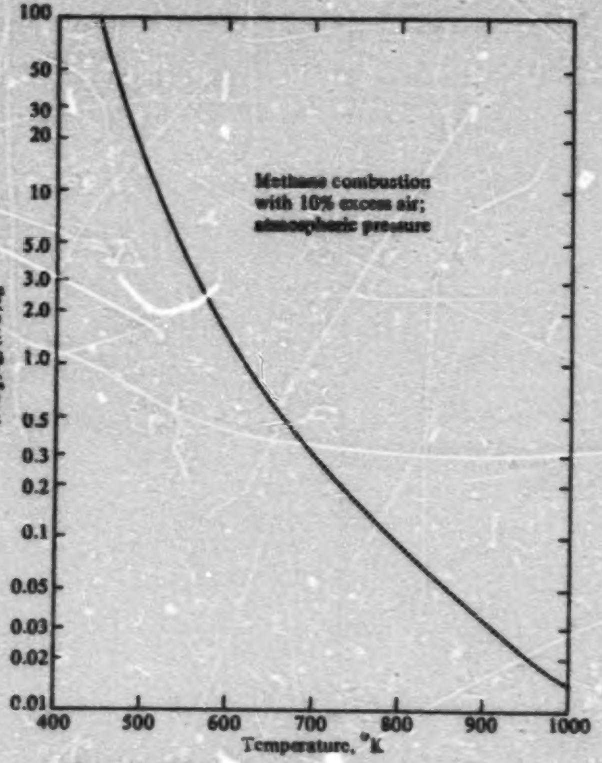

Figure 38. Effect of temperature on equilibrium concentrations of NO and NO_2 in combustion gases (3).

where R is the gas constant and T the absolute temperature. This expression shows that NO is thermodynamically stable only at high temperature; figure 39 illustrates the variation in equilibrium NO concentration with temperature and air stoichiometry. Figure 40 further emphasizes the sensitivity of NO concentration to air stoichiometry. Highest NO concentration occurs at 10-15% excess air even though the peak flame temperature occurs at only 95% stoichiometric air, indicating that the availability of oxygen limits the equilibrium concentration of NO. Typical equilibrium concentrations of NO and NO_2 in air and flue gas are found in table 9 (24).

Residence time at peak flame temperature is usually insufficient for NO to reach equilibrium concentration; therefore, the kinetics of NO formation have important bearing on final NO_x concentration in the flue gas. The reaction mechanism of NO formation is now thought to be a chain reaction involving oxygen and nitrogen free radicals (35). The high activation energy for the fixation reaction, about 135 Kcal/mole (3, 35), is responsible for the extreme temperature dependence of this reaction.

From the standpoint of NO_x emission control the decomposition rate of NO to nitrogen and oxygen is also quite important (3). Although NO becomes thermodynamically unstable as the flame temperature decreases, the decomposition rate becomes so low that below 1260-1320° C the NO concentration becomes fixed (3). As the flue gas is diffused into the atmosphere the NO may combine with oxygen to yield NO_2.

The type of fuel used in power plants may have a pronounced effect on NO_x emission levels. Based on adiabatic flame temperature, one may expect that NO_x emission rates will be highest for coal-fired boilers, followed in descending order by oil and gas. The actual situation is more complex, of course, because NO_x formation will also depend on heat transfer rates in the boiler and the chemically bound nitrogen content of the fuel.

Coal and oil are prone to burn with luminous flames which increase heat transfer and flame quench rates. Gas usually burns with a blue flame, the emissivity of which is much lower than the luminous oil and coal flames. Because the heat transfer rate of such flames is low, the flame is quenched more slowly. Thus, in large boilers where almost all heat transfer is by radiation, natural gas fired boilers may actually produce more NO_x than coal or oil fired boilers. The Southern California Edison Company (1), for example, reports that, in general, NO_x emissions have increased with unit size, and for units of 480-mw or larger, NO_x emissions are greater for gas fuel than for residual oil.

A second reason that fuel type is important lies in the fact that coal and oil contain chemically bound nitrogen. One may expect that oxygen would more easily attack the more reactive N-N or N-C bonds in fuel molecules than the N ≡ N bond of molecular nitrogen. Convincing

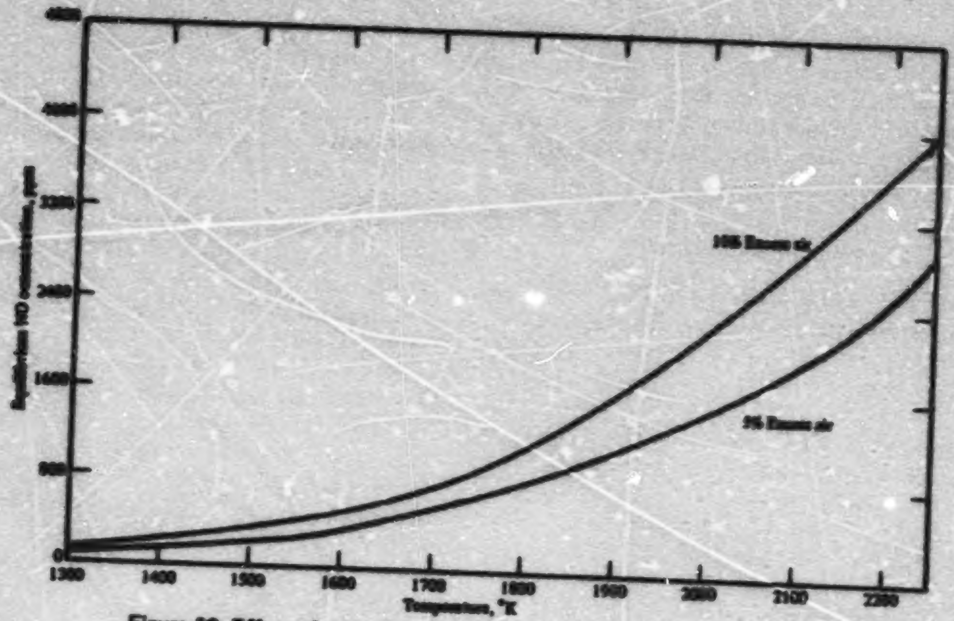

Figure 39. Effect of temperature on equilibrium concentrations of NO for combustion of methane (3).

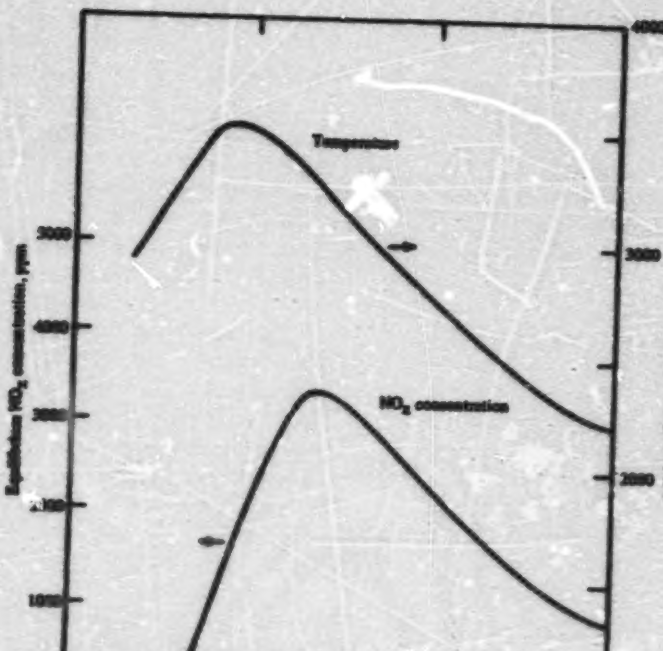

Figure 40. Effects of air concentration on NO_x equilibrium in methane–air flames (3).

Table 9. Equilibrium concentration of NO_x in air and in a typical flue gas at 1 atm (24).

Temperature, °C	Air		Flue gas[a]	
	NO (ppm)	NO_2 (ppm)	NO (ppm)	NO_2 (ppm)
527	2.3	0.71	0.77	0.11
1600	6,100	12	2,000	1.8

[a] 3.3% O_2, 76% N_2.

experimental evidence of this comes from the Argonne National Laboratory (49). Fluidized bed combustion of coal occurs at about 900° C, too low for nitrogen fixation to occur. Yet, workers at Argonne found that in one set of fluidized bed experiments using air, NO concentration in the offgas was about 500 ppm. Substitution of inert argon for nitrogen produced essentially no change in the offgas NO concentration, thus showing that the source of the NO was nitrogen chemically bound in the coal.

Crynes and Maddox (24) have divided nitrogen oxide emission control into three broad categories: fuel treatment, combustion control, and flue gas cleanup. Fuel treatment to remove chemically bound nitrogen does not, at present, appear technologically possible.

Because nitrogen oxide concentration is sensitive to flame temperature and length of time reactants are exposed to peak flame temperature, some NO_X control is possible through modification of the time temperature profile by means of boiler and combustion changes. In practice, modification of existing boilers may be both difficult and expensive.

Nitrogen oxide production is significantly decreased by lowering the excess oxygen concentration (1) but, unfortunately, combustion efficiency is lowered also. This problem can be circumvented by adding slightly less than stoichiometric air through the primary air ports with additional air being added "downstream" to complete combustion (1, 41). It is claimed that significant reductions in NO concentration are possible with only moderate increase in operating costs (1, 2, 41). Decreasing the enthalpy per unit volume of reactants can lower the peak combustion temperature and thus the NO formation rate (2). This may be accomplished by simply reducing combustion air preheat or recirculating product gases and mixing these with the combustion air. The inert product gases absorb a fraction of heat of combustion and, in effect, reduce the peak flame temperature.

A third method of NO_X control involves stack gas cleanup. So far, catalytic decomposition, selective reduction of NO with ammonia, hydrogen sulfide, or hydrogen, adsorption on solid supports, and aqueous scrubbing with alkaline solutions such as $Mg(OH)_2$ or concentrated sulfuric acid have been considered.

Schmidt *et al* (74) have described the use of $Mg(OH)_2$ and $MgCO_3$ for scrubbing NO_X from nitric acid plant offgas. As was discussed in the previous section, an adaption of this process has since been suggested for NO_X removal from power plant offgas (27). Figure 41 shows a flow diagram of the NO_X control system.

In the scrubber, magnesium hydroxide or carbonate slurry absorbs the nitrogen oxides to yield magnesium nitrite, some magnesium nitrate, and, if sulfur dioxide removal is not complete, magnesium sulfate. The magnesium nitrite solution is sent to a decomposition tank where nearly pure NO is liberated at elevated temperature and pressure, via the reaction:

$$3Mg(NO_2)_2 + 2H_2O \rightarrow Mg(NO_3)_2 + 2Mg(OH)_2 + 4NO\uparrow \qquad (39)$$

The resulting suspension is treated with ammonia and carbon dioxide to yield $Mg(OH)_2$ and $MgCO_3$ for recycle to

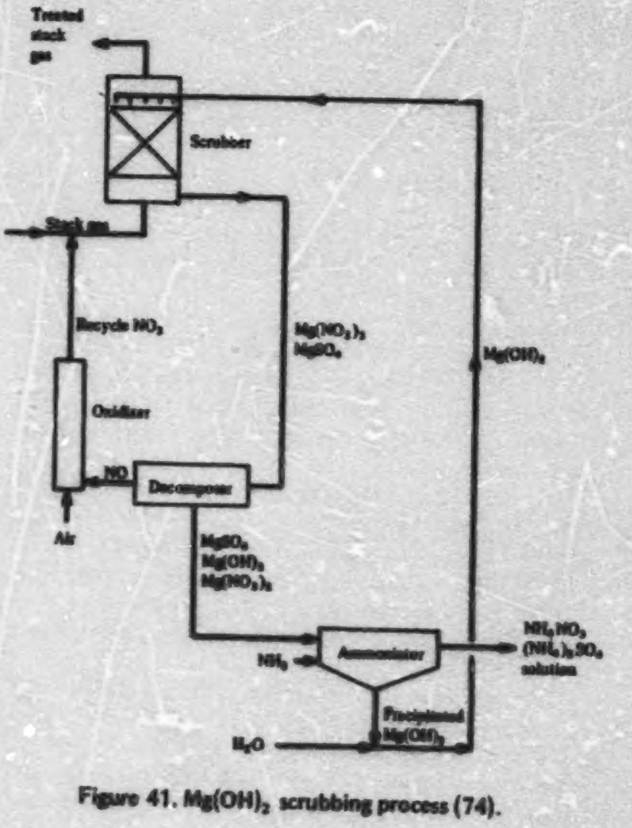

Figure 41. $Mg(OH)_2$ scrubbing process (74).

either the NO_X or SO_2 scrubbers and a solution of NH_4NO_3 which may be sent to an ammonium nitrate manufacturing plant.

$$(NH_4)_2CO_3 + Mg(NO_3)_2 \rightarrow 2NH_4NO_3 + MgCO_3 \downarrow \qquad (40)$$

The NO from reaction is air oxidized to NO_2 and injected into the flue gas in an amount sufficient to maximize the N_2O_3 concentration.

Any sulfate formed in the scrubber would be removed from the system as soluble ammonium sulfate in the ammonium nitrate stream.

Alternately. Downs and Kubasco (27), see figure 8, have suggested the addition of sufficient slaked lime to the stream leaving the NO_X scrubber to precipitate the sulfate as $CaSO_4$.

$$Ca(OH)_2 + MgSO_4 \rightarrow CaSO_4 \downarrow + Mg(OH)_2 \downarrow \qquad (41)$$

Unless provision is made for recovery, this process alternate will lead to some magnesium losses, but because of the paucity of engineering data, no choice can be made between the alternates at this time.

Because of the unreactivity of NO (relative to NO_2 or N_2O_3), efficient scrubbing with H_2SO_4 or aqueous alkaline solutions hinges on the idea of injecting NO_2 into the flue gas prior to the absorption step.

In the presence of water vapor, Downs and Kubasco assume the following gas phase reaction:

$$H_2O + NO + NO_2 \rightleftharpoons 2HNO_2 \qquad (42)$$

Although the equilibria is shifted well toward the left, favorable kinetics with continuous HNO_2 removal will drive the reaction to completion.

In a more recent study (26), using a 1500 cfm spray type scrubber, Downs evaluated NO_X scrubbing efficiency with MgO as a function of liquid to gas ratio, NO_2 to NO ratio, MgO slurry concentration, stoichiometry, and gas flow rate. Under all conditions tested, scrubbing efficiency was less than 10%.

Assuming liquid film resistance to HNO_2 transfer is negligible, the expected HNO_2 mass transfer rate, K_ga, should be near 23.0 lb moles/hr-ft^3 and the NO_X absorption efficiency about 33%. Since the observed absorption efficiency and corresponding K_ga are much lower, Downs concludes that liquid film resistance to HNO_2 absorption is significant.

The minimum NO_X absorption efficiency necessary to produce a self-sustained supply of NO_X is 75%. To achieve even this modest efficiency, the K_ga must exceed 72 moles/hr-ft^3. Because this mass transfer rate is nearly 100 times the observed K_ga, Downs concludes that it is not physically possible to design a spray type scrubber which will increase the nitrous acid mass transfer coefficient this much. Thus, a system such as MgO that is liquid-film mass-transfer or chemical-reaction-rate limiting will not perform.

If MgO dissolution is the rate limiting step, then it is possible that the nitrous acid mass transfer coefficient might be increased to the necessary 72 lb moles/hr-ft^3 by using a soluble basic absorbent such as Na_2CO_3 instead. Downs feels that for soluble salts such as sodium carbonate, a packed tower has the best chance of success.

Recovery As Sulfur

Although process schemes evaluated in this study call for the conversion of flue gas sulfur oxides to sulfuric acid, there are advantages in recovering the sulfur values as elemental sulfur. These advantages include lower shipping costs (per mole of sulfur) and fewer storage problems. There are at least two possible routes to elemental sulfur:

1. Catalytic reduction of a stream rich in sulfur dioxide to elemental sulfur by addition of carbon, natural gas, or carbon monoxide.
2. Production of hydrogen sulfide in the calciner with subsequent conversion of the H_2S to elemental sulfur.

The first route, reduction of sulfur dioxide to elemental sulfur, is now in operation in at least two plants (36, 99). One process (36) uses the hot reducing gases from partial combustion of Bunker C fuel oil to reduce SO_2 to elemental sulfur. In a process developed by Allied Chemical (99), methane gas is used to reduce SO_2 to elemental sulfur. The Allied Chemical process is described in more detail below. These systems are quaternary, containing carbon, oxygen, sulfur, and hydrogen. Alternately, it is possible to reduce SO_2 with carbon or carbon monoxide, in which case the system would be ternary.

Kellogg (52), who has developed the principal features of both systems from thermochemical calculations, demonstrates that critical control problems occur in attaining the maximum sulfur recovery in any process which reduces SO_2 with carbon, hydrocarbons, or carbon monoxide.

For example, in the ternary oxygen-carbon-sulfur system, starting with a pure SO_2 stream and carbon as reducing agent, the elemental sulfur concentration reaches a maximum at a carbon to oxygen atom ratio of 0.5, but as shown in figure 42, potential sulfur recovery sharply decreases at either side of this optimum ratio. Thus, below C/O ratio 0.5, both SO_2 and S_2O partial pressures rapidly increase with decreasing C/O ratio while above a ratio 0.5, COS and CS_2 increase. A possible method of achieving the optimum ratio, Kellogg suggests, would be to add excess carbon at elevated temperature, then bleed in the required amount of SO_2 to achieve C/O ratio 0.5 for maximum sulfur recovery.

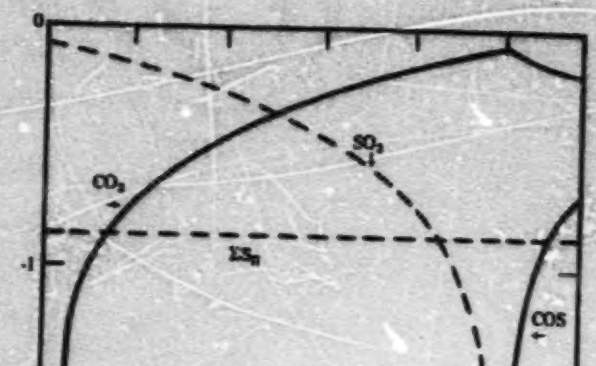

Figure 42. Effect of C/O atom ratio on gas composition for the system C-O-S at 600° K and one atmosphere total pressure (52).

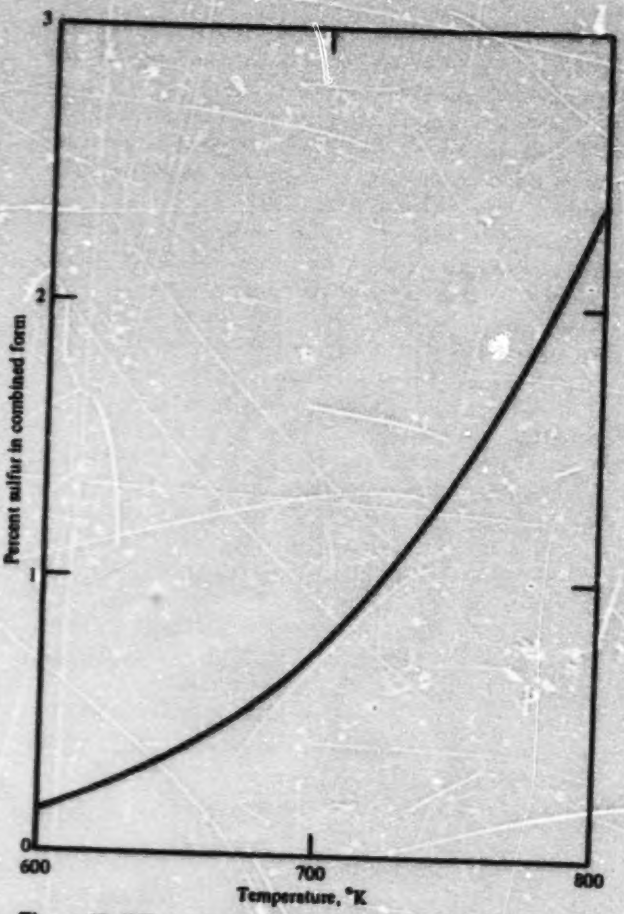

Figure 43. Effect of temperature on elemental sulfur recovery in the system C-O-S at P = 1 atm, S/O = 0.5 and C/O = 0.5 (composition for optimum production of sulfur) (52).

Potential sulfur recovery also increases with decreasing temperature. Again starting with carbon and a pure SO_2 stream, figure 43 shows that about 99.8% of the sulfur is elementai (.02% combined) at 625° K, the remainder being predominantly COS and SO_2. Achieving practical reaction rates at this low temperature requires an activated alumina catalyst. The dew point of sulfur under optimum experimental conditions is 597° K and, therefore, the reaction temperature must remain above this temperature to prevent condensing sulfur from fouling the catalyst.

At 625° K, the reaction between carbon and SO_2 is far too slow to be practical; thus, elevated temperature, perhaps as high as 1200° K, may be necessary for rapid reaction. At higher temperature, the undesirable products, COS, CS_2, and H_2S predominate, and the reaction mixture must be cooled to optimum temperature of 625° K and allowed to equilibrate before condensing the sulfur.

Using carbon monoxide as the reductant, optimum sulfur recovery also occurs at a C/O ratio of 0.5, but because the product gas is leaner in sulfur, condensation may be more difficult. This problem may be offset by the fact that carbon monoxide reacts with sulfur dioxide much faster than does solid carbon and, thus, a lower initial reaction temperature can be used.

Methane is an alternate but less effective reductant than carbon or carbon monoxide. Kellogg shows that, at 600° K, 88.5% of the sulfur, at most, can be recovered as elemental sulfur in one pass through the reaction chamber. Recovery as high as 95% is possible by taking the offgas from the first condensation through a second condensation at lower temperature. The lower temperature of the second condensation will not condense liquid sulfur because the dew point has been sharply altered by the first condensation. To achieve optimum sulfur recovery, the [C + H]/O atom ratio must be 1.25. As before, small departures from this ratio sharply reduce the yield of elemental sulfur.

Finally, any inert gas in the system, such as nitrogen, in effect lowers the partial pressure of gaseous sulfur and makes condensation less efficient. For maximum sulfur recovery, inert gas should be avoided.

A possible alternate sulfur recovery process might include hydrogen sulfide production directly in the calciner followed by conversion of the H_2S to elemental sulfur. Based on thermochemical calculations, Sillen and Andersson (81) have shown that H_2S production in the calciner should be possible under reducing conditions. However, their calculations did not include the possible gas phase species COS and CS_2. In an oxidizing atmosphere, such omissions should not be critical since these species would not be present. In a reducing atmosphere, one can envision significant amounts of COS, CS_2, or elemental sulfur, and for this reason, the equilibrium gas phase composition of the quaternary system, C-O-S-H, was reexamined at 1200° K.

The gas phase constituents considered in the calculation were S_2, SO_2 SO_3, O_2, H_2S, H_2O, H_2, CO_2, CO, COS, and CS_2. Because the partial pressure of the sulfur polymers S_3 through S_8 is thought to be negligible (34), these were not considered in the analysis. The following seven equilibria were used to express the relationship between the eleven gas phase species.

$$CO_2 + \frac{3S_2}{2} = CS_2 + SO_2 \qquad (43)$$

$$\frac{3S_2}{2} + 2CO_2 = 2COS + SO_2 \qquad (44)$$

$$SO_2 + \tfrac{1}{2}O_2 = SO_3 \qquad (45)$$

$$CO + \tfrac{1}{2}S_2 = COS \qquad (46)$$

$$\tfrac{1}{2}O_2 + H_2 = H_2O \qquad (47)$$

$$\tfrac{1}{2}S_2 + H_2 = H_2S \qquad (48)$$

$$\tfrac{1}{2}O_2 + CO = CO_2 \qquad (49)$$

The eleven partial pressures which appear in the equilibria are determined by simultaneous solution of eleven equations: seven equilibrium constant equations, three equations which specify the system composition, and a final equation relating the total pressure to the sum of the partial pressures. The latter four equations are shown below; P_T, C/S, H/S, and O/S are, respectively, total pressure and mole ratio of carbon to sulfur, hydrogen to sulfur, and oxygen to sulfur:

$$P_T = P_{CO} + P_{CO_2} = P_{H_2O} + P_{H_2} + P_{S_2} + P_{H_2S} + P_{SO_2} + P_{SO_3} + P_{COS} + P_{CS_2} + P_{O_2} \qquad (50)$$

$$C/S = \frac{P_{CO} + P_{CO_2} + P_{COS} + P_{CS_2}}{P_{SO_2} + P_{SO_3} + P_{H_2S} + 2P_{CS_2} + P_{COS} + 2P_{S_2}} \qquad (51)$$

$$H/S = \frac{2P_{H_2} + 2P_{H_2S} + 2P_{H_2O}}{P_{SO_2} + P_{SO_3} + P_{H_2S} + 2P_{CS_2} + P_{COS} + 2P_{S_2}} \qquad (52)$$

$$O/S = \frac{2P_{CO_2} + P_{CO} + 2P_{SO_2} + 3P_{SO_3} + 2P_{O_2} + P_{H_2O} + P_{COS}}{P_{SO_2} + P_{SO_3} + P_{H_2S} + 2P_{CS_2} + P_{COS} + 2P_{S_2}} \qquad (53)$$

All thermochemical data required in the calculation were taken from the JANAF tables (46). Ideal gas behavior was assumed at one atmosphere, but if an inert gas such as nitrogen were present, the total pressure of the system would be correspondingly lower.

A box central composite design was used to cover the region of interest, which was C/S ratio 1.0 to 3.0, H/S ratio 1.0 to 3.0, and S/O ratio 4.0 to 6.0—fifteen data points in all.

An iterative method similar to Kellogg's was used with a digital computer to solve the eleven simultaneous equations at each of the fifteen points. The method consists of substituting starting value partial pressures of four representative species containing carbon, hydrogen, oxygen, and sulfur into the equilibria expressions to give values of the remaining seven partial pressures. The set of eleven partial pressures is substituted into the total pressure and ratio equations to yield interim values of P_T and the three mole ratios. The differences between the interim values and the desired values are computed and compared with the convergence criteria (0.02% of the desired value). If any one of the differences is greater than the convergence criteria, four new starting values of CO_2, H_2, H_2O, and H_2S are computed and the process repeated. The iteration procedure continues until either the convergence criteria is satisfied or to a preset number of iterations if the partial pressure values do not converge. New starting values are computed from the following equations:

$$\log \underset{new}{CO_2} = \log \underset{old}{CO_2} + \log \left[\frac{P}{P*} \cdot \frac{(C/S)}{(C/S)*}\right]^{\frac{1}{T}} \qquad (54)$$

$$\log \underset{new}{H_2} = \log \underset{old}{H_2} + \log \left[\frac{P}{P*} \cdot \frac{(H/S)}{(H/S)*}\right]^{\frac{1}{U}} \qquad (55)$$

$$\log \underset{new}{H_2O} = \log \underset{old}{H_2O} + \log \left[\frac{P}{P*} \cdot \frac{(O/S)}{(O/S)*}\right]^{\frac{1}{V}} \qquad (56)$$

$$\log \underset{new}{H_2S} = \log \underset{old}{H_2S} + \log \left[\frac{P}{P*}\right]^{\frac{1}{W}} \qquad (57)$$

where the asterisk indicates interim values. The components T, U, V, and W are integers used to manipulate the rate of convergence. The fifteen calculated equilibrium hydrogen sulfide partial pressures were used to generate by regression analysis the polynomial shown below, which represents hydrogen sulfide partial pressure as a function of system composition.

$$P_{H_2S} = b_0 + b_1X_1 + b_2X_2 + b_3X_3 + b_{11}X_1^2 + b_{22}X_2^2 + b_{33}X_3^2 + b_{12}X_1X_2 + b_{13}X_1X_3 + b_{23}X_2X_3 \quad (58)$$

where X_1 = C/S, X_2 = H/S, and X_3 = O/S. The correlation coefficient was 0.9845, indicating that the data were well represented by the equation.

In a complicated system such as this, there is sometimes difficulty in analyzing and simplifying the large amount of partial pressure data. By using a method of constrained nonlinear programming (37), it was possible to determine that the gas phase composition which maximized the H_2S partial pressure within the region of experimentation was C/S = 3.0, H/S = 3.0, and O/S = 4.0. The gas composition under these conditions at total pressures of 1.0 or 0.5 atmospheres is shown in table 10.

With a total pressure of combustion products of either 0.5 or 1.0 atm, approximately 80 mole % of the sulfur is present as H_2S with carbonyl sulfide and elemental sulfur comprising the remainder. The gas composition of 0.5 atm would correspond to a sweep gas of half inert nitrogen, half combustion products.

As presently conceived, the magnesium sulfite calciner will be swept at about 1200° K with the hot gases from combustion of a number 6 fuel oil with air. The sweep gas will contain almost 60% nitrogen and have C/S, H/S, and O/S ratios of 0.73, 1.50, and 4.31, respectively.

By modification of the combustion conditions and addition of enough coke to the calciner to approach optimum conditions, a gas stream containing about 80 mole % of the sulfur as H_2S will be obtained. Cooling this stream and blending SO_2 into it to yield the optimum (C + H)/O ratio will maximize the sulfur content of the stream.

With the multiple condensation suggested by Kellogg, 95% sulfur recovery is possible when no inert gases are present in the gas stream. The presence of nearly 60% nitrogen in the stream presents an obstacle to efficient sulfur recovery, but if the fuel oil were burned with pure oxygen, this difficulty would be removed.

Alternately, a series of sulfur condensations at successively lower temperature will make it possible to efficiently recover elemental sulfur. Allied Chemical (99) has developed such a system at its Falconbridge facility in Ontario, Canada. The plant is designed to treat 500 tons per day sulfur contained in a roaster gas of composition (dry basis) 12-13% sulfur and 1-1.5% oxygen and remove 90% or more of the inlet sulfur.

The system consists of three sections: a gas purification system and a high temperature reactor followed by a low temperature Claus reactor system.

Particulate matter and catalyst poisons are wet scrubbed from the roaster offgas and the sulfur dioxide is catalytically reduced with methane in the high temperature reactor to elementary sulfur, hydrogen sulfide, and lesser amounts of other sulfur compounds. The elemental sulfur is condensed out of the gas and the remaining sulfur compounds sent to a two-stage Claus converted for further sulfur recovery. Additional sulfur condensation occurs after the Claus system.

Methane gas was chosen as reducing agent because of availability and economics, but other reductants such as carbon monoxide or hydrogen could also be used.

Table 10. Effect of total pressure on gas phase composition.

Component	Partial pressure (atm) at one atmosphere total pressure	Partial pressure (atm) at 0.5 atmosphere total pressure
CO	0.46	0.23
CO_2	0.17	0.84×10^{-1}
COS	0.27×10^{-1}	0.13×10^{-1}
CS_2	0.98×10^{-3}	0.42×10^{-3}
H_2	0.10	0.53×10^{-1}
H_2O	0.51×10^{-1}	0.26×10^{-1}
H_2S	0.18	0.86×10^{-1}
O_2	0.40×10^{-16}	0.39×10^{-16}
S_2	0.62×10^{-2}	0.53×10^{-2}
SO_2	0.28×10^{-5}	0.25×10^{-5}
SO_3	0.53×10^{-14}	0.46×10^{-14}

STUDY ASSUMPTIONS AND DESIGN CRITERIA

The magnesia slurry process and three proposed variations are given detailed consideration in the present study. Although other products are possible, each scheme is designed to produce 98% sulfuric acid.

Scheme A, magnesia slurry process—Wet scrubbing of stack gas with an aqueous magnesium oxide-sulfite slurry to absorb SO_2 and form additional crystalline $MgSO_3 \cdot 6H_2O$. The $MgSO_3 \cdot 6H_2O$ is thermally converted to $MgSO_3 \cdot 3H_2O$ which is dried to form anhydrous $MgSO_3$. This material, along with 5-10% $MgSO_4$ formed by oxidation, is calcined to generate MgO for recycle to the scrubbers and SO_2-rich gas for production of sulfuric acid by the contact process. Coke is used to reduce the sulfate to SO_2 and MgO. This scheme follows closely the development work of Chemico-Basic, B & W, the Russians, and the Japanese.

Scheme B, MgO-MnO$_2$ slurry variation—Wet scrubbing of stack gas in a cocurrent spray device to absorb SO_2 with an aqueous magnesium oxide-sulfite slurry containing an activator, manganese oxide. The crystalline $MgSO_3 \cdot 6H_2O$ formed is thermally converted to $MgSO_3 \cdot 3H_2O$; the resulting crystals are dried to anhydrous $MgSO_3$, $MgSO_4$, and compounds of manganese. These materials are calcined to generate Mg_6MnO_8 for recycle to the scrubbers and SO_2-rich gas for production of sulfuric acid by the contact process. This scheme is an adaptation of the Grillo-Werke development with modifications.

Scheme C, clear liquor variation—Wet scrubbing of stack gas to remove particulates and absorb SO_2 with an acidic solution of magnesium bisulfite and magnesium sulfite, followed by separation of insoluble fly ash and liquor, and addition of MgO to the liquor to precipitate crystalline $MgSO_3 \cdot 6H_2O$. The $MgSO_3 \cdot 6H_2O$ is thermally converted to $MgSO_3 \cdot 3H_2O$ which is dried to form anhydrous $MgSO_3$. The drier product including $MgSO_3$ and 5-10% $MgSO_4$ is calcined with coke to yield MgO for recycle to the reactor and scrubbers and generate SO_2 rich gas for production of sulfuric acid by the contact process. This scheme follows closely the development work of Chemico-Basic. Although available design data were based on a venturi type scrubber, other designs using slightly different operating conditions should be feasible.

Scheme D, central processing concept—On-site wet scrubbing of stack gas with magnesia slurry to absorb SO_2 and form crystalline $MgSO_3 \cdot 6H_2O$ followed by thermal conversion to $MgSO_3 \cdot 3H_2O$ as in Scheme A. The trihydrate crystals are dried on site to produce anhydrous $MgSO_3$, which is shipped to an off-site central processing unit capable of calcining $MgSO_3$ from several source locations. Recycle MgO is shipped back to each scrubber location and the SO_2-rich calciner offgas is converted to sulfuric acid in a more economically sized contact plant. By avoiding dependency on a single source of magnesium sulfite, this process variation of Scheme A permits more efficient design and operation of the calcination and acid manufacturing steps as compared to an on-site system subject to the cyclic nature of power plant operation to meet electrical demand.

Schemes A, B, and D can be applied to either coal- or oil-fired units, however, coal-fired units require particulate removal in a separate step prior to absorption of SO_2. Scheme C, an alternative in which sulfites are kept in solution to permit removal of particulates and SO_2 simultaneously in a single scrubber, is applicable only to coal-fired; since little fly ash is emitted from oil-fired units, the more effective slurry schemes can be used.

Fuels

In the previous conceptual design studies, primary attention was given to control of SO_2 from coal-fired power units, coal being the predominant fossil fuel utilized in U. S. plants and producing the largest quantity of emitted SO_2. With only minor differences, the earlier conceptual designs were applicable to both coal- and oil fired units. However, in the present study, there are more distinct and important differences between control systems for power units burning coal or oil; therefore, coverage will be expanded to give both fuels complete attention.

Previous conceptual design reports considered the burning of coal with sulfur contents of 2.0, 3.5, and 5.0%. These sulfur levels were selected to evaluate the economics of sulfur dioxide removal from power plant stack gas over the range of sulfur levels of coal reported in the literature (94), and will be used again in the current report. As before, the coal is assumed to contain 12% ash and have a total heating value of 12,000 Btu/lb. Although coals having higher ash content and lower heating value are becoming more predominant, these values are still representative of coal mined in the midwestern U. S.

A survey to obtain representative fuel oil characteristics indicated that compositions of fuel oil, like coal, vary considerably. Since sulfur content of fuel oil generally is less than for coal, concentrations of 1.0, 2.5, and 4.0% sulfur were assumed. These are fairly typical of values reported in the literature. A No. 6 fuel oil with a 15° API gravity and an ash content of 0.1% is assumed to be a representative fuel and a typical total heating value of 18,500 Btu/lb or 149,000 Btu/gal is assumed for all sulfur levels (75).

Flue Gas Composition

To serve as a basis for flowsheet calculations, it is desirable to define distinct flue gas compositions for both coal- and oil-fired systems. Although NO_x removal by the magnesia process is not well enough defined to justify detailed treatment in this report, flue gas compositions will include an NO_x concentration. In doing so, it is necessary to give NO_x special consideration since its concentration, unlike SO_2, depends primarily on boiler design, excess air, and flame temperature, rather than fuel characteristics.

Available literature sources indicate that for various types of coal-fired boilers NO_x concentrations range from about 200 to 1200 ppm by volume (5, 25), whereas, concentrations for similar type oil-fired boilers range from about 100 to 900 ppm (3, 4). Since the concentrations vary over a wide range, compositions of flue gas are estimated for two of the more common boiler types for both coal- and oil-fired units. Pulverized coal (horizontal, frontal-fired) and cyclone-fired boilers were considered for the coal-fired units, whereas, tangential-fired, and horizontal, frontal-fired boilers were considered for the oil-fired units. The concentrations of NO_x in the flue gas from these type boilers are included in the estimated flue gas compositions presented later.

As in the previous conceptual design reports, flue gas compositions for coal firing are based on combustion with 20% excess air to the boiler, and 13% additional air inleakage at the air preheater. These values reflect operating experience with TVA frontal-fired, coal-burning units. For oil-fired units, flue gas compositions were estimated assuming 5% excess air to the boiler with an estimated 10% air inleakage at the air preheater. Reflecting coal-fired boiler operating experience, it was assumed that 75% of the ash present in coal is emitted as fly ash from pulverized coal (horizontal, frontal-fired) boilers, whereas only 25% of the ash is emitted from cyclone-fired boilers. For the oil-fired units, it was assumed that all of the ash in the fuel oil is emitted. The complete flue gas analyses covering both fuels are given in tables 11 and 12.

Emission Standards

The EPA has established emission standards for new steam generating facilities as shown in table 13 (29).

In this report, process and equipment designs will meet the standards for particulate and SO_2 emission. As indicated earlier, the magnesia process does not appear to be capable of reducing NO_x emission more than 10% at best and should not be relied upon for meeting NO_x emission standards. A more successful approach might be accomplished by modifying the boiler firing system. Furthermore, some commercial boilers currently available are capable of meeting NO_x emission standards.

Plant Location

Sulfuric acid is one of the world's most widely used industrial chemicals. Although it is consumed in large quantities in many industrial applications, the largest end use is for the production of phosphate fertilizers. In the U. S., the Midwest is the area of greatest fertilizer usage and for purposes of this study, it has been assumed that the power unit is located in this section of the country. In addition, location on a navigable river is desirable since it may be possible to ship large quantities of sulfuric acid by barge to fertilizer plants not located in the immediate vicinity of the power plant.

For evaluation of the central processing concept (Scheme D), metropolitan areas of Chicago, Illinois, and Philadelphia, Pennsylvania, are arbitrarily chosen as locations for recovery systems since this concept appears practical only for locations having many sources of sulfur dioxide emissions. Shipping costs in these areas will be used in the economic evaluation of Scheme D.

Plant Size and Status

The size of fossil-fueled power plants currently being built ranges up to 1300-mw. At this time, the largest operating unit is a 1130-mw TVA boiler; however, several other units as large as 1300-mw are expected onstream in the next few years (30). Although a considerable portion of the future generating capacity will be from power units 500-mw or larger, 200-mw and smaller units will continue to be utilized. It is expected that the majority of the older and smaller units will be operated as peaking stations; however, some new 200-300-mw units may be used for base loads.

To determine the effect of power plant size on the economics of sulfur dioxide recovery, three unit sizes, 200, 500, and 1000-mw, are given detailed attention in the conceptual design. In addition, both new and existing units are studied since they usually have differences in input heat requirements, remaining years of operating, and installation expense (new vs retrofit) for particulate and SO_2 removal devices. Representative heat rates used in this study are shown in table 14. These rates are assumed to be applicable for either coal- or oil-fired units.

Table 11. Estimated flue gas compositions for coal-fired boilers at various nitrogen oxide and sulfur levels, percent by volume.

Boiler type	Pulverized coal (horizontal, frontal-fired)			Cyclone-fired		
Nitrogen oxides in flue gas, ppm by vol.		600			1,200	
Sulfur content of coal, % by wt	2.0	3.5	5.0	2.0	3.5	5.0
Flue gas composition, % by volume						
Nitrogen	74.62	74.55	74.49	74.59	74.52	74.46
Carbon dioxide	12.57	12.55	12.54	12.57	12.55	12.54
Oxygen	4.86	4.86	4.85	4.83	4.83	4.82
Water	7.77	7.76	7.75	7.77	7.76	7.75
Sulfur dioxide	0.12	0.22	0.31	0.12	0.22	0.31
Sulfur tioxide	0.001	0.001	0.001	0.001	0.001	0.001
Nitrogen oxides	0.06	0.06	0.06	0.12	0.12	0.12
Fly ash loading						
Grains/SCF dry	4.11	4.11	4.11	1.37	1.37	1.37
Grains/SCF wet	3.79	3.79	3.79	1.26	1.26	1.26

Table 12. Estimated flue gas compositions for oil-fired boilers at various nitrogen oxide and sulfur levels, percent by volume.

Boiler type	Tangential-fired			Horizontal, frontal-fired		
Nitrogen oxides in flue gas, ppm by vol.		200			600	
Sulfur content of oil, % by wt	1.0	2.5	4.0	1.0	2.5	4.0
Flue gas composition, % by volume						
Nitrogen	73.83	73.73	73.64	73.81	73.71	73.62
Carbon dioxide	12.52	12.37	12.21	12.52	12.37	12.21
Oxygen	2.55	2.55	2.54	2.53	2.53	2.52
Water	11.03	11.19	11.37	11.03	11.19	11.37
Sulfur dioxide	0.05	0.14	0.22	0.05	0.14	0.22
Sulfur trioxide	0.001	0.001	0.001	0.001	0.001	0.001
Nitrogen oxides	0.02	0.02	0.02	0.06	0.06	0.06
Fly ash loading						
Grains/SCF dry	0.035	0.036	0.037	0.035	0.036	0.037
Grains/SCF wet	0.031	0.032	0.033	0.031	0.032	0.033

Plant Life, Operating Time, and Capacity Factor

Based on power plant evaluation guidelines suggested by the Federal Power Commission (31), the expected operating life of a new fossil-fueled power unit is about 30 years. Historically, the highest operating rates (onstream time) occur during the first 10 years of operation and decline thereafter. Reflecting TVA experience (83), table 15 shows the power plant operating schedule assumed in this study. This schedule is equivalent to a chemical plant operating at 8000 hr/yr for 16 years.

Since existing power units can be expected to have less remaining years of operation at high capacity factors, power plant age is also an important parameter. In this study, existing 200-mw units are assumed to have 22 years remaining life (8 years old) and 500-mw and 1000-mw units are assumed to have 27 years remaining life (3 years old). In each case, the first

Table 13. Emission standards for new steam generating facilities.

Boiler type	Allowable emission, pounds per million Btu heat input	
	Coal fired	Oil fired
Particulates	0.1	0.1
Sulfur dioxide	1.2	0.8
Nitrogen oxide, expressed as NO_2	0.7	0.3

Table 14. Power unit input heat requirements.

Unit size, mw	Btu/kwh
1,000 new	8,700
1,000 existing	9,000
500 new	9,000
500 existing	9,200
200 new	9,200
200 existing	9,500

Table 15. Assumed power plant capacity schedule.

Year of life	Capacity factor, % (nameplate rating)	Annual kwh/kw capacity
1-10	80	7,000
11-15	57	5,000
16-20	40	3,500
21-30	17	1,500

few years of operation at a high capacity factor are assumed lost.

When considering sulfur dioxide control processes for power plants, both the tendency of units to decline in utilization over their operating life and the intermittent operation on a daily basis due to electrical demand variation should be recognized. For recovery processes in particular, the associated large investment requirements and market commitments usually make it desirable to operate the recovery system at a high capacity factor to minimize the effect of the continuing fixed capital charges on unit production costs.

Maintaining a high capacity factor may not be possible where a single facility is involved (as in Schemes A, B, and C); however, by utilizing the central processing concept (Scheme D), the effect of fluctuations in power plant load and operation can be minimized for the regeneration and sulfuric acid systems. Using feed material from several independent sources, this unit can operate on a more uniform schedule similar to that of most chemical plants, say, 8,000 hr/yr. For purposes of this report, it is assumed that the operating life of the central processing unit is 10 years. If shipping costs are not excessive, such a system should be more economical than units tied to a single power plant boiler.

Flue Gas and Sulfur Dioxide Rates

The parameters which determine the amounts of flue gas and sulfur oxides emitted from coal- and oil-fired power units have been discussed. Since design of sulfur dioxide recovery units is dependent upon actual quantities of gas and SO_2 as well as gas compositions indicated earlier, calculated flue gas and equivalent sulfur dioxide emission rates as both SO_2 and sulfuric acid are tabulated in table 16. Volumetric flue gas rates to the scrubbing system are based on a gas temperature of 310° F at the exit of the air preheater.

Degree of Sulfur Dioxide Removal

From the analyses of fuels and Federal emission standards presented earlier, it can be seen that required SO_2 removal efficiencies vary depending on the sulfur content and type of fuel. The required removal efficiencies are tabulated in table 17 for the various fuels and sulfur levels considered in this study.

Before emission standards were defined, previous conceptual designs arbitrarily provided for 90% removal of sulfur dioxide from the stack gas. Since test data show that three of the four magnesia scrubbing schemes are capable of achieving this degree of sulfur dioxide removal, a 90% removal efficiency also is provided for these systems so that comparisons with previously studied processes can be made. Indications are that the fourth scheme, the clear liquor process, may be capable of only 70-85% SO_2 removal; therefore, only design provisions necessary to meet the emission standard will be provided.

Stack Gas Reheat

The need for stack gas reheat for plume buoyancy has been recognized, but the degree of reheat required has not been well established. The effect of temperature on plume buoyancy and ground-level concentration of stack gas constituents was studied in detail for the limestone-wet scrubbing conceptual design (89). The results indicated that with a high degree of sulfur dioxide removal (80% or above), the stack gas temperature is not critical. However, to prevent high ground-level concentrations during adverse atmospheric conditions, reheat from 125 to 175° F is provided in this conceptual design.

In the magnesia process, some reheat is obtained from dryer offgas and exhaust fan compression, but additional heat is needed to reach 175° F at the stack exit. For new coal-fired power units, indirect steam reheat is provided since new units can be designed to supply steam to the

Table 16. Flue gas and sulfur dioxide emission rates.

Power plant size, mw	Type plant	Sulfur content of fuel, %	Gas flow to scrubbers, acfm (310° F)	Equivalent sulfur dioxide emission rates	
				Lbs SO_2/hr	Tons 100% H_2SO_4/hr
Coal-fired units					
200	New	3.5	630 M	9,310	7.1
200	Existing	3.5	650 M	9,610	7.4
500	New	2.0	1,540 M	13,010	10.0
500	New	3.5	1,540 M	22,760	17.4
500	New	5.0	1,540 M	32,510	24.9
500	Existing	3.5	1,570 M	23,270	17.8
1,000	New	3.5	2,980 M	44,000	33.7
1,000	Existing	3.5	3,080 M	45,520	34.9
Oil-fired units					
200	New	1.0	530 M	1,990	1.5
200	New	2.5	530 M	4,960	3.8
200	New	4.0	530 M	7,940	6.1
200	Existing	2.5	550 M	5,130	3.9
500	New	1.0	1,300 M	4,850	3.7
500	New	2.5	1,300 M	12,140	9.3
500	New	4.0	1,300 M	19,420	14.9
500	Existing	2.5	1,320 M	12,410	9.5
1,000	New	1.0	2,510 M	9,390	7.2
1,000	New	2.5	2,510 M	23,470	18.0
1,000	New	4.0	2,510 M	37,540	28.7
1,000	Existing	2.5	2,590 M	24,280	18.6

scrubbing area. In cases of existing coal-fired and both new and existing oil-fired power units, direct gas reheat is provided from combustion of fuel oil. As discussed in the limestone-wet scrubbing conceptual design study, other reheat methods can be utilized; however, these two are probably the simplest to install and most reliable for their respective applications. They are probably in the mid-cost range as compared to other choices such as cyclic liquid-gas heat exchange and gas to gas heat exchanger.

Dust Removal

Combustion of pulverized coal containing 12% ash in a frontal-fired boiler results in a dust emission of 7.5 lb/million Btu (~4 grains/acf) at the boiler exhaust; with a cyclone boiler, the fly ash content is about one third this amount. Combustion of fuel oil containing 0.1% ash produces a dust emission of 0.054 lb/million Btu (0.04 grain/cu ft). A comparison of these dust loadings with the emission standards given earlier indicates the need to remove a minimum of 98.6% of the dust emitted from coal, frontal-fired boilers to meet Federal emission standards, whereas no additional facilities are required for oil-fired units unless dictated by local law.

Table 17. Required SO_2 removal efficiencies.

Fuel	Required degree of SO_2 removal, %
Coal	
2.0% S	60.9
3.5% S	77.6
5.0% S	84.4
Oil	
1.0% S	26.0
2.5% S	70.4
4.0% S	81.5

Because of the regenerative and cyclic nature of MgO scrubbing processes, it is necessary to minimize the amount of contaminants which are introduced into the sulfur dioxide scrubbing loop. Since high dust removal efficiencies are desirable to prevent possible contaminant buildup, the processes are designed to attain at least 99% dust removal. The most common types of equipment for controlling particulate emissions are mechanical collectors, fabric filters, eletrostatic precipitators, and wet scrubbers; however, mechanical collectors are not capable of attaining high removal efficiencies, and fabric filters are generally too expensive for use in handling large volumes of flue gas. Presently, electrostatic precipitators are the most widely accepted type of equipment for control of fly ash in modern power plants, but experience has shown these units to be expensive to install and maintain and occasionally unreliable for attaining high removal efficiencies over long periods of time. Wet scrubbing of flue gas has the disadvantage of lowering the temperature and buoyancy of the gas by humidification. Since the MgO schemes control SO_2 emission by wet scrubbing, provisions for reheat are required regardless of the method used for dust removal; thus, wet scrubbing is the logical method for removing dust in these schemes.

Many existing coal-fired power units already have electrostatic precipitators in operation, but some are not capable of attaining the desired removal efficiency. Arbitrarily, it will be assumed that these precipitators will be kept in operation. However, due to the need for maximum dust removal discussed above, existing coal-fired units will also be equipped with particulate scrubbers capable of attaining dust removal efficiencies of 99%.

Amount of Storage

The amount of storage which should be provided for a product depends largely upon its consumption rate for each end use. Since sulfuric acid is an intermediate product which usually undergoes further processing, the largest storage burden is often passed on to the industrial consumer rather than the producer. However, to provide for large consumer and cyclic markets such as the phosphate fertilizer industry, storage requirements of 30 days or more are not uncommon. In this study, 30 days storage is provided, with facilities included for up to three product acid concentrations. In addition, 4 weeks storage is included for fresh makeup MgO and coke. A minimum period of 1 day is provided for in-process storage of $MgSO_3$ and recycle MgO to give some flexibility of operation. For the central processing concept (Scheme D), $MgSO_3$ and recycle MgO storage is increased to 3 days to cover possible transportation delays.

Base Case

The base case chosen for Schemes A, C, and D of the magnesia scrubbing conceptual design is a new 500-mw power unit with a horizontal, frontal-fired boiler utilizing coal containing 3.5% sulfur. The base case chosen for Scheme B, the MgO-MnO_2 variation, is a new 500-mw power unit with a horizontal, frontal-fired boiler utilizing fuel oil containing 2.5% sulfur. Although several cases for both coal- and oil-fired units are evaluated in this report, flowsheets are presented for the base cases only, since most of the detailed design and cost data were obtained for these systems, and a major effort would be required to present separate flowsheets for each case.

Process Flowsheets

Process flowsheets and material balance tables representing base case conditions for each scheme are shown in Appendix B and are designated as follows:

	Figure
Scheme A -	B-1
	B-2
Scheme B -	B-3
	B-4
Scheme C -	B-5
	B-6
Scheme D -	B-7
	B-8

Solid Waste Disposal

Fly ash collected in the particulate scrubbers of coal-fired power plants is pumped as an 8 to 20% solids slurry to a fly ash storage pond. In this study it is assumed that the ash is allowed to settle and clarified water is recycled back to the particulate scrubbers to minimize the consumption of fresh water and to reduce contamination of nearby streams. A power plant to pond distance of 1 mile is assumed for cost estimates. Although not required in all cases, costs for ash neutralization facilities are included in the investment, and slaked lime is provided for neutralization of SO_3 absorbed in the particulate scrubbers.

Insoluble contaminants removed from the SO_2 scrubber system by purge treatment are disposed in the ash pond. Concentrated soluble contaminants from the system are pumped to an evaporative pond for direct disposal, with no return of water.

Miscellaneous

The increased pressure drop of flue gas due to operation of wet scrubbers requires that higher energy fans be provided. For new power units, a single fan capable of overcoming the pressure drop incurred in both the boiler and scrubbing equipment is included for each duct. The investment cost assigned to the scrubbing area is assumed to equal the incremental cost between a new fan to handle the total pressure drop and one to handle the pressure drop of the power unit alone. For existing units, the investment cost of new fans to handle the pressure drop of the scrubbing system alone is provided. The operating cost for these fans is divided between the power plant and the recovery unit according to the pressure drop incurred in each area.

An optional bypass duct is provided for each scheme to allow for continued operation of the power plant during unscheduled shutdown of the scrubbing system. The investment for the bypass ducts is itemized separately in the cost tables (Appendix A). Flue gas ducts are designed for average gas velocities of 50 ft/sec.

Spare pumps are provided to prevent operational shutdowns due to pump failure; however, no other spare equipment is included in the estimates.

For Schemes A, B, and C representing on-site facilities, magnesium oxide losses due to handling and conveying are assumed to be 2.0%. Losses for Scheme D, which represents off-site central processing and requires considerable additional materials handling, are assumed to be 3.0%, 50% greater than for on-site operations.

EQUIPMENT SELECTION AND DESCRIPTION

The facilities required for scrubbing stack gas with magnesia slurry and regeneration of the absorbent can be divided into the following major equipment categories:

1. Particulate control
2. Sulfur dioxide absorption and stack gas reheat
3. Slurry or solution processing
4. Sulfite drying-calcining
5. Magnesia slurry preparation
6. Sulfuric acid production
7. Sulfuric acid storage
8. Fuel oil storage
9. Optional bypass duct

Prior to description of specific equipment items for each category, several alternatives are considered with emphasis on both performance and cost. A discussion of the major alternatives for the magnesia schemes along with available data, curves, and design information follows.

Scrubbing Alternatives

Particulate control–Combustion of pulverized coal containing ash results in the release of much of the ash as fine dust particles that escape, at least partially, with the combustion gas. Although the composition of the ash varies widely from source to source, a typical ash composition of a western Kentucky coal is indicated in table 18 (84).

As discussed earlier, the portion of ash present in the coal which eventually is emitted depends upon the type of boiler: a pulverized coal (horizontal, frontal-fired) boiler typically emits about 75% of the ash present in the coal as fly ash, as compared to approximately 25% for cyclone-fired boilers. Although the particle size distribution of fly ash is likely to vary considerably, a sample distribution is shown in table 19 (87).

As mentioned earlier, wet scrubbing was selected as the method for controlling particulate emission in the magnesia schemes. Of the various types of wet scrubbers available, a venturi was chosen for control of particulates since it is generally considered to be the least costly device capable of attaining the high dust removal efficiencies desired. The Babcock and Wilcox Company has reported specific data for removal of fly ash from the combustion gases of a pilot-size, coal-fired boiler using a venturi scrubber (27). This data, presented in figure 44, shows a relationship between pressure drop and fly ash collection efficiency at an L/G of 15 gal/Macf and is used in this report.

Several methods of fly ash disposal, including trucking to off-site locations and on-site ponding, are used in the industry. For the magnesia cases studied, only the on-site ponding technique is considered. Off-site disposal would be more expensive for large power units; however, this may not be true for small units.

In the on-site ash disposal system, effluent from the particulate scrubbers is received in a surge tank designed for partial clarification of the recycle stream. A thickened underflow containing about 8-20% fly ash is pumped to an on-site fly ash disposal pond, and a return line and pumps are provided for recycle of clarified pond water to the particulate scrubbers. The distance from the scrubbers to the pond is assumed to be 1 mile.

Table 18. Typical ash composition of a western Kentucky coal (84).

Constituent	Percent by weight
CaO	6.1
MgO	1.1
Al_2O_3	20.5
Fe_2O_3	16.9
SiO_2	44.9
S	1.9
K_2O	0.8
Na_2O	0.3
Unknown	7.5
	100.0

Table 19. Particle size distribution of fly ash (87).

Particle size, microns	Percent of total number of particles	Percent by weight
0.5 and smaller	57.2	0.13
1	20.5	0.37
2	10.6	1.5
3	5.2	2.5
4	3.0	3.5
5 to 9	3.0	17.0
10 to 100	0.5	75.0
	100.0	100.0

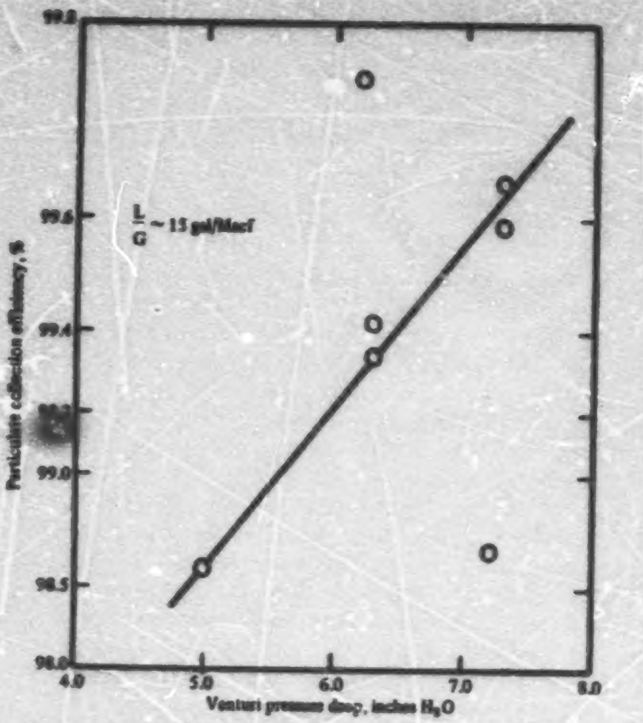

Figure 44. Effect of pressure drop on particulate collection efficiency for a venturi scrubber (27).

In many cases, the effluent from the fly ash scrubber is acidic with initial pH determined partially by the amount of sulfur dioxide or sulfur trioxide absorbed in the particulate scrubber. The composition and amount of fly ash collected in the particulate scrubber also affects the pH of the scrubber effluent; however, slow response times are normally encountered because fly ash is relatively insoluble and the final pH is not quickly attained. Although the composition of fly ash is likely to vary for different coal sources, operating experience in the TVA system indicates that a basic pond water is normally encountered when dry collected fly ash is sluiced with water. Since little experience is available to indicate the final pH which would result from prolonged contact of an acidic scrubber effluent with a basic fly ash, slaked lime addition facilities can be included in the fly ash disposal circuit for neutralizing all sulfur oxides absorbed in the particulate scrubber. This measure may not be necessary for all applications; however, it provides insurance against possible leakage of acidic pond water into other streams.

Sulfur dioxide absorption and stack gas reheat—The absorber types considered for stack gas magnesia scrubbing processes include packed, tray, mobile bed, venturi, and spray devices. Packed and tray scrubbers are the most common absorbers used in the chemical industry; however, they are not often used for slurry service due to their tendency to plug. Based on discussions with vendors of these devices, it is recommended that they not be used in Schemes A, B, and D which utilize slurries and are expected to have a tendency to form scale deposits. For the clear liquor process which requires simultaneous particulate and SO_2 removal, these scrubber types are suitable for the sulfur dioxide absorption; however, they are generally not effective for attaining high dust removal efficiencies, and their use in magnesia scrubbing is questionable.

The mobile bed, venturi, and spray absorbers are capable of operating with either clear liquor or slurry absorbents and can be considered for all four magnesia process schemes. Scaling is less a problem for mobile bed absorbers because the turbulent action of the internal bouncing balls minimizes accumulation. Also, scaling is usually not a problem for venturi absorbers because high gas velocities and simple internal design inhibit scale formation. Because of the high gas velocities, however, venturi absorbers generally consume more energy from the gas and result in higher operating pressure drops than other type absorbers. Spray absorbers usually operate with greater residence time and lower pressure drop than venturi absorbers by utilizing gas velocities similar to packed, tray, or mobile bed absorbers. However, they do not contain internal packing, and absorption efficiencies are generally lower than for the above type absorbers. Scaling can be minimized in spray scrubbers by designing for high liquid to gas ratio which reduces the effect of solids formation; the flushing action of high irrigation rates tends to prevent accumulation of deposits. In the spray scrubber application developed by Grillo for MgO-MnO_2 scrubbing (Scheme B), a high gas velocity is utilized (49 ft/sec), but the added manganese dioxide is said to promote the rapid absorption necessary to achieve good efficiency.

The absorption of sulfur dioxide from power plant stack gas by magnesia scrubbing has been evaluated by the Babcock and Wilcox Company for both mobile bed and venturi absorbers and by Chemico Basic for the venturi type. It is understood that the spray absorber is the only device Grillo has tested using the MgO-MnO_2 slurry concept.

The conceptual designs of the magnesia schemes are based on the relationships which follow.

The effect of liquid to gas irrigation ratio on sulfur dioxide absorption efficiency for slurry scrubbing with a mobile bed absorber is shown in figure 45 (27). A similar relationship for slurry scrubbing using a venturi absorber (12) is shown in figure 46. The data indicate that sulfur dioxide removal efficiency increases with an increase in L/G. Both absorber types are capable of attaining sulfur dioxide absorption efficiencies of 90% or greater; however, a venturi absorber requires a higher operating L/G to

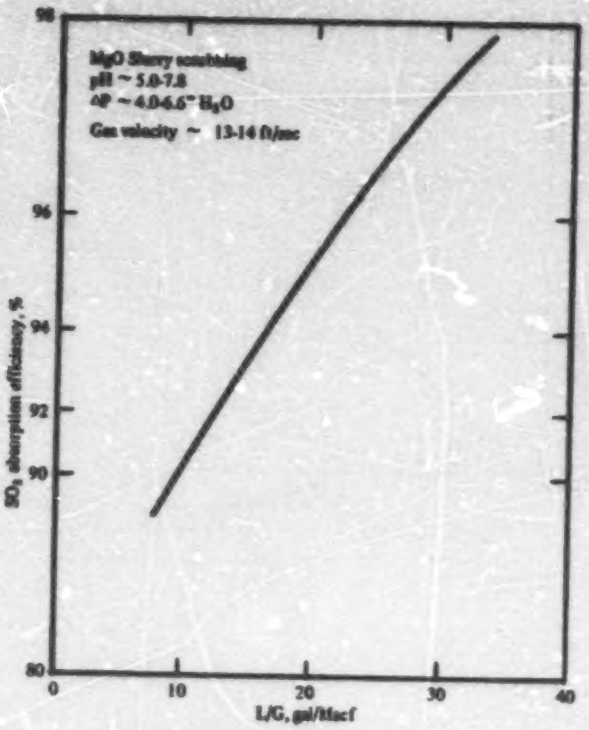

Figure 45. Effect of liquid to gas irrigation ratio on sulfur dioxide absorption efficiency for a mobile bed absorber (27).

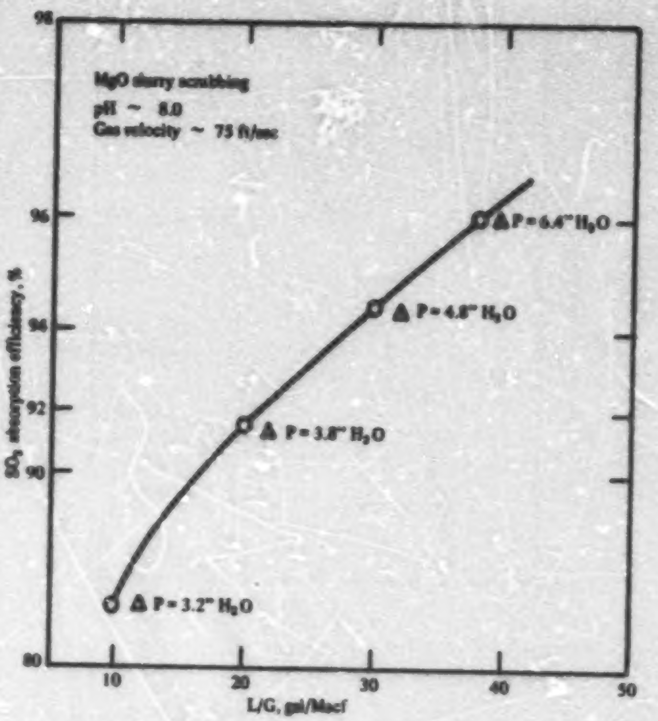

Figure 46. Effect of liquid to gas irrigation ratio on sulfur dioxide absorption efficiency for a venturi absorber (12).

achieve the same absorption efficiency as that of a mobile bed absorber.

The effect of liquid to gas irrigation ratio on sulfur dioxide absorption efficiency for spray scrubbing using the MgO-MnO_2 slurry variation is shown in figure 47 (61). These results indicate that the spray scrubber is capable of achieving high sulfur dioxide absorption efficiencies at relatively low values of L/G for this process.

A linear relationship exists between pressure drop and L/G for slurry scrubbing with a mobile bed absorber as indicated in figure 48 (27). The effect of pressure drop on SO_2 absorption efficiency for slurry scrubbing with a venturi (27) is indicated in figure 49. Although the correlation is based on a minimum amount of data at elevated pressure drops, it is in close agreement with similar data obtained by Chemico-Basic during slurry scrubbing tests at the Canal Electric Company (12).

Since pH is a function of the scrubbing liquor composition, the effect of pH on absorption efficiency is an important parameter, as indicated in figure 50 (27), for slurry scrubbing using a mobile bed absorber operating at various pressure drops. The data indicate that increased absorption efficiencies are obtained with either increased pressure drop or higher pH. A similar relationship for a venturi absorber is shown in figure 51 (27). The solid curve represents actual data for a venturi absorber operating at a pressure drop of 1.5 in. of water. Since data were not given for absorption efficiencies at higher pressure drops, the dashed curve is projected based on data for venturi absorbers operating at higher pressure drops as indicated in figures 46 and 49.

The effect of pH on sulfur dioxide absorption efficiency for spray absorption using the MgO-MnO_2 slurry scheme is shown in figure 52 (40).

Best operation for this process variation is reported to be at pH values ranging from 6.0 to 7.5.

Clear liquor scrubbing processes can be designed to operate either at a low pH (5.0-6.0) with moderate concentrations of soluble magnesium bisulfite-sulfite absorbent in the liquor or a higher pH (6.5-7.5) with low concentrations of soluble absorbent. The main disadvantage of the low pH method is the high solution vapor pressures of SO_2 which restrict achievable absorption efficiencies. For higher pH values near 7.0, control is difficult, especially in restricting scale deposition from solids formation. The very low solubility of absorbent with basic pH values requires extremely high liquor to gas irrigation to provide for the desired amount of absorption. Although test work

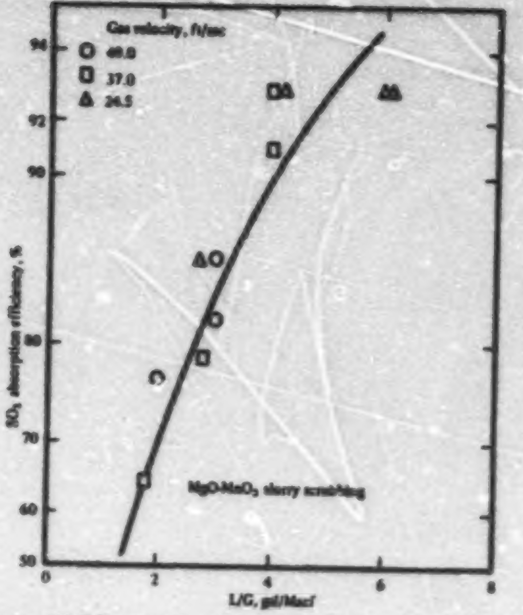

Figure 47. Effect of liquid to gas irrigation ratio on sulfur dioxide absorption efficiency for a spray absorber (61).

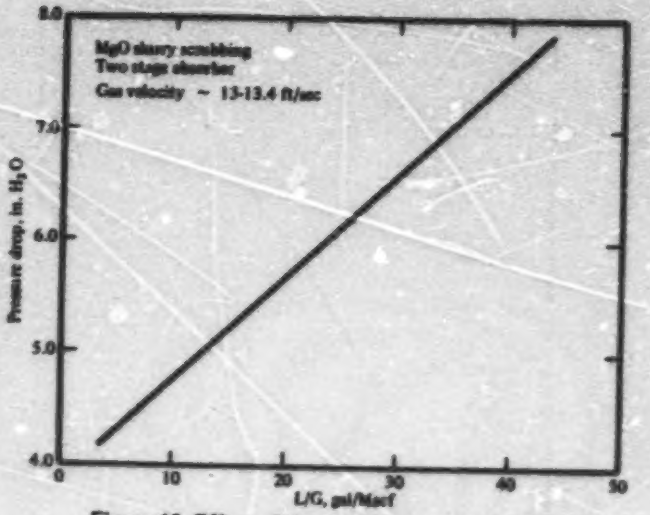

Figure 48. Effect of liquid to gas irrigation ratio on pressure drop for a mobile bed absorber (27).

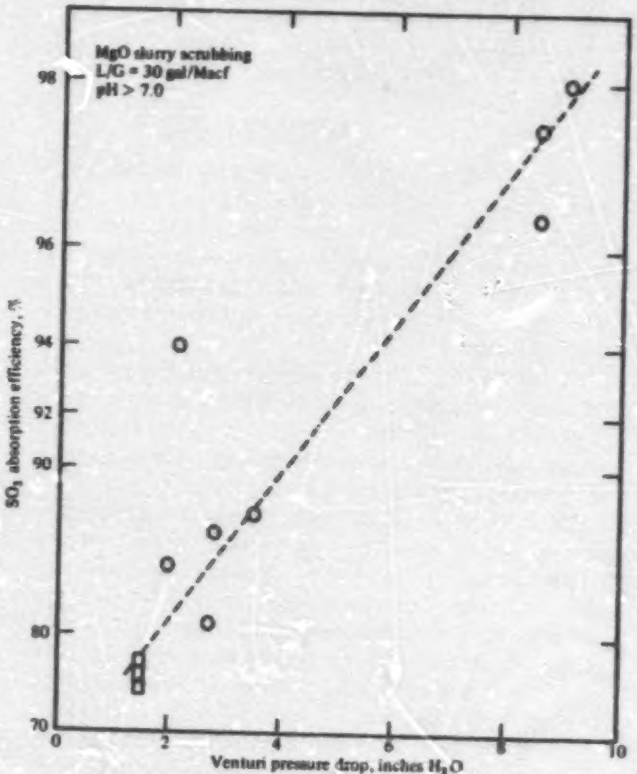

Figure 49. Effect of pressure drop on sulfur dioxide absorption efficiency for a venturi absorber (27).

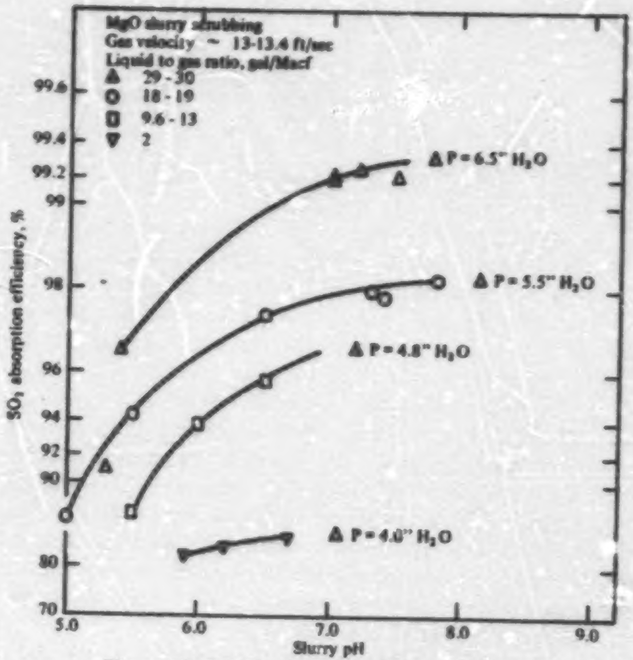

Figure 50. Effect of slurry pH on sulfur dioxide absorption efficiency for a mobile bed absorber (27).

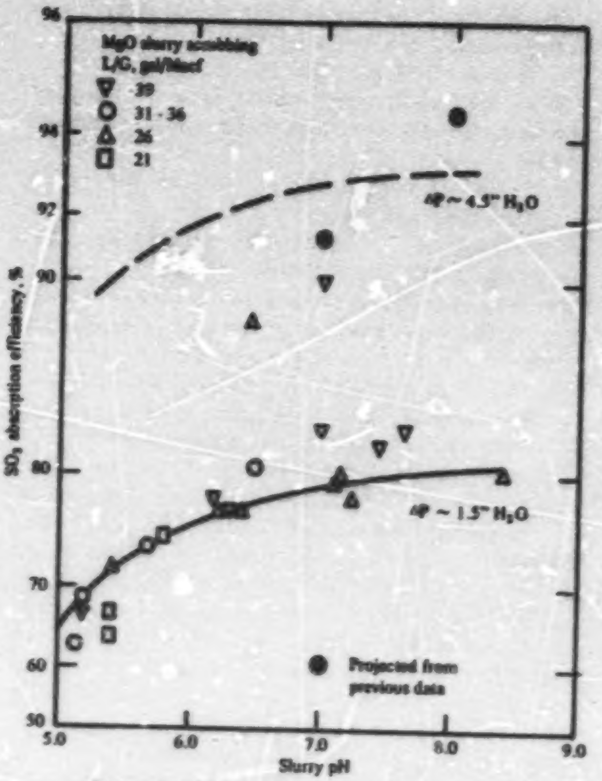

Figure 51. Effect of slurry pH on sulfur dioxide absorption efficiency for a venturi absorber (27).

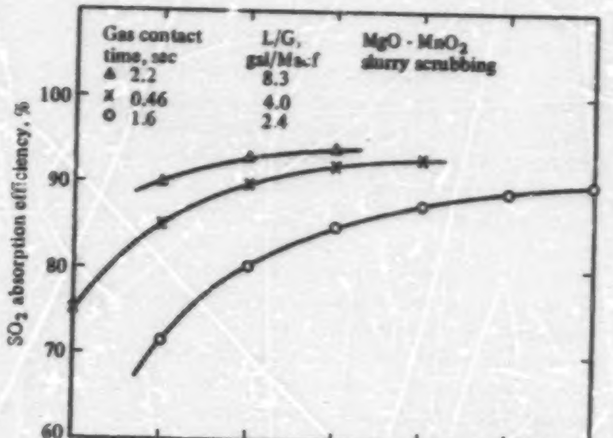

Figure 52. Effect of slurry pH on sulfur dioxide absorption efficiency for a spray absorber (40).

on the clear liquor scheme has been limited, unpublished data provided by Chemico-Basic for absorption of SO_2 from pulverized coal combustion gas using a venturi scrubber indicates the efficiency attainable. The data, tabulated in table 20, were obtained for operation of the venturi at pressure drops ranging from 12.5 to 15.0 in. of water and at an L/G of approximately 20 gal/Macf.

The effect of other parameters on sulfur dioxide absorption efficiencies by magnesia slurry scrubbing which were determined in the EPA-Babcock and Wilcox pilot program are discussed below.

1. Absorption increases with increasing MgO to SO_2 stoichiometric ratio to a molar ratio of 1.0. Above this value absorption does not increase significantly.

2. The presence of fly ash in the gas to the sulfur dioxide absorber does not affect sulfur dioxide absorption levels.

3. The presence of high concentrations of dissolved magnesium sulfate reduces sulfur dioxide absorption in the low pH range. At higher pH, sulfur dioxide absorption is not affected.

4. Conversion of magnesium oxide to the hydroxide before injection into the absorber does not improve sulfur dioxide absorption.

5. Increasing the total liquid holdup time including the time in the sump does not improve sulfur dioxide absorption.

Because of the lack of pilot plant data to verify absorption capabilities, spray scrubbers were not selected for Schemes A, C, or D. By the same reasoning, venturi and mobile bed absorbers were not utilized as the scrubber type for Scheme B. Before considering these alternate scrubber choices, operation of a spray scrubber without MnO_2 activator should be tested as well as operation of venturi or mobile bed absorbers with MnO_2 addition, since variations are likely.

Mobile bed absorbers appear to be more effective than venturi absorbers for absorption of SO_2 in magnesia slurry, but both types appear capable of reducing SO_2 to an acceptable level. Therefore, costs and actual performance over extended periods become the primary considerations for selection. In discussions with vendors, it was determined that several different designs and materials of construction

Table 20. Absorption efficiencies attainable with clear liquor scrubbing scheme.

Recirculating liquor, pH	Absorption efficiency, %
6.0	76
5.8	71
5.7	77
5.5	77
5.5	81
5.2	72

are being considered, but that predicted total costs (investment and operating) for complete systems of either venturi or mobile bed scrubbers are very close. Selection for an actual installation should be based on the latest cost quotations and performance results to determine which absorber is more attractive. For purposes of this report, the design parameters required for both types of scrubbers will be given with the equipment descriptions to follow and the flowsheets in Appendix B will reflect the ranges of liquid irrigation necessary for both devices. Cost data given in the text and the Appendix A tables on the sulfur dioxide portion of the scrubbing system for Schemes A, C, and D are probably closer to the venturi option.

Design provisions for operational turndown or temporary shutdown of any one magnesia scrubbing system will depend primarily on how that unit operates in its total system. Base load power units of large size will not require as extensive flexibility as smaller units used in peaking service. Generally, 200-mw systems with as many as six coal feeders are not operated at less than 25-33% of load so that in the event of failure in a feed system at least one operating feeder is left. If other power generation facilities are available, midrange base load units such as a 500-mw facility are usually restricted to a turndown around 50-60%; operation at loads less than 50% justifies complete shutdown and shift of load to a smaller peaking unit.

Several methods are available to provide turndown capabilities including:

1. Multiple scrubbing trains
2. Variable flow control to individual scrubbers
3. Compartmentalized scrubbers
4. Individual scrubber bypasses
5. Connecting plenum ducts between trains

These different methods affect both duct and scrubber design and, unfortunately, little experience is available to indicate which method is best. In limited TVA pilot plant tests of a Turbulent Contact Absorber (mobile bed type) with limestone scrubbing, reasonable dust and SO_2 removal efficiencies were maintained during operation at gas rates as low as 50% of design capacity. In the large scale demonstration systems for SO_2 removal being constructed in 1972 around the country, a variety of these alternatives are being utilized, in many cases, provision is made for more than one alternative.

For this conceptual design study, a variable throat control is provided for the particulate venturi to maintain high gas velocities when operating at reduced gas rates. Other than possible changes in liquid circulation rate, no specific provisions are included for the SO_2 scrubbers. To provide isolation for temporary shutdowns, each train of scrubbers is equipped with sufficient shutoff dampers and a bypass duct; however, when using these provisions, a portion of the boiler gas is exhausted without particulate and SO_2 control.

The use of a mist eliminator in the SO_2 scrubber exit gas duct is desirable for the following purposes:

1. To reduce the load on the stack gas reheater.
2. To decrease the deposition of liquid and entrained solids in ducts and equipment located downstream from the scrubber.
3. To reduce the amount of solids emitted to the atmosphere as entrained dust.
4. To minimize the amount of makeup MgO required to compensate for losses out the stack.

For maximum efficiency and extended service, mist eliminators should be designed for proper gas distribution and include facilities for removing any accumulated solids.

In previous process studies (87, 89) several types of mist eliminators were evaluated. The simplest and most common are the impingement vane types in which the shape of the vanes and their arrangement cause impaction and coalescence of the mist. Other types of entrainment separators evaluated included centrifugal vane, wire mesh (York), fiber bed (Brink), cyclonic, and packed bed (6-12 in. of Tellerettes, Pall Rings, or other packing). Although it may be possible to adequately reduce mist with these devices, there is some uncertainty about the ability of some types to operate in slurry service without plugging. Presently more large-scale gas scrubber installations are utilizing chevron vane type mist eliminators, or slight modifications, because they are generally considered the type least likely to plug. Although experience in power unit service is limited, scrubber vendors are recommending the use of fiberglass reinforced polyester chevron vane type mist eliminators for the magnesia schemes; therefore, such devices will be used in this study. Considerable doubt still exists as to their effectiveness and reliability over long periods of time; however, extended tests such as the Boston Edison demonstration should provide better information than currently available.

Various methods for supplemental reheat of the stack gas were discussed in previous conceptual design studies. For this report the alternatives are repeated and updated where additional information applies. Portions of the required flue gas reheat are obtained from heat of compression of the gas in passing through the induced draft fans and from direct addition of dryer exhaust to the main flue gas stream; however, supplemental heat is required to obtain a stack gas outlet temperature of 175° F. Table 21 shows the expected temperature rise or loss of the gas in passing through the system.

Additional heat may be supplied by installing a combustion system at the base of the power plant stack for burning natural gas, oil, or coal and mixing the combustion products with the scrubber exit gas. The main advantages for this method are moderately low investment, flexibility in degree of reheat, minimum added pressure drop, low maintenance, and good reliability. Disadvantages are fuel

Table 21. Flue gas temperature.

	°F
Exit temperature from mist eliminator	127
Expected temperature rise through induced draft fan	14
Expected temperature rise from dryer offgas	5
Expected temperature loss in stack	-4
Reheat required	33
Net temperature out of stack	175

cost, introduction of objectionable components (SO_3, SO_2, and ash) into the gas, and fuel supply problems. Natural gas is the most desirable fuel; however, gas supplies are extremely limited and probably restricted from many power plants. Oil would be more expensive, but since already required by the process, a practical alternative. Use of coal could result in the lowest fuel cost, but would add more sulfur dioxide and ash to the stack gas. The fly ash emission could be minimized by firing the coal on a grate stoker.

A second reheat choice is to bypass the scrubber with part of the gas stream and mix this gas with the scrubber exit gas. This procedure requires minimum investment and has essentially no operating cost. However, it requires that higher particulate and SO_2 removal efficiencies be obtained in the scrubber since a portion of the gas is emitted to the atmosphere without being scrubbed. This is not a desirable alternative.

A third reheat method uses heat exchangers for direct transfer of heat from the scrubber inlet gas to the exhaust gas. With this method, heat that would be wasted is recovered. Further advantages are reduction in the amount of water required for evaporative cooling, a corresponding reduction in gas volume and, except for maintenance, no labor requirement. Disadvantages are the large heat exchanger required (because of low transfer coefficient and temperature differential), high pressure drop, and possibility of fouling–which would lead to low efficiency and high maintenance cost. Corrosion by sulfur trioxide would be a problem.

Using a cyclic-liquid heat exchange system with heat transfer from the inlet gas to treated water and from the water to the scrubber exhaust gas is another alternative. The better heat transfer coefficient would permit use of smaller exchangers than those required for gas-gas exchange and the smaller surface would reduce pressure drop and maintenance. Fouling, corrosion, and erosion problems are major disadvantages.

Heating with steam from the turbine cycle in a heat exchanger at the scrubber outlet is one of the more popular reheat techniques. This method would require additional fuel in the boiler to generate the extra steam and modification of the turbine to allow higher than normal extraction rates. Extensive modification of existing units would be impractical, but in a new plant a system could be included to provide the steam required.

Use of steam for reheat would require relatively small heat exchangers installed only on the scrubber discharge where if mist eliminators are effective, the gas should be relatively clean. Corrosion, fouling, and pressure drop would be minimized. The main disadvantage is the added fuel requirement.

Finally, a sixth reheat system considered uses a cyclic system comprised of heat exchange towers where liquid or solid particles are sprayed into the gas stream ahead of the scrubber and the sensible heat gained by the particles is transferred to the scrubber exit gas in a similar chamber. With this system, there would be no heat exchangers to foul or corrode and the pressure drop would be low. With a liquid, partial dust removal could be effected by filtering or centrifuging the liquid from the "hot" tower. However, a low vapor pressure over the liquid would be required to prevent carryover to the scrubber and the liquid should be nonflammable or have a high kindling temperature to prevent fire hazard. Use of solid particles would require a material with good abrasion resistance to withstand the rough handling.

As discussed in the Study Assumptions and Design Criteria section, at this time, simplicity and reliability are more important considerations for selection of the method for stack gas reheat than are costs. On a performance basis, direct combustion and steam reheat are probably the most desirable methods. Although other concepts may also prove to be reliable, these two are chosen for use in the current study. Because of lower cost and the ability to provide for in the original design, the steam reheat method is incorporated in new coal-fired power units; all other cases utilize the direct combustion method. Since fuel oil is used at each plant to supply the heat for drying, it was selected as the fuel for the combustion reheat systems.

There are three alternatives for location of the fan for new coal-fired installations, including:

1. Upstream of the scrubbing system
2. Between particulate and sulfur dioxide scrubbers
3. Downstream from the scrubbing system

For new oil-fired installations the second location is not applicable since particulate scrubbers are not utilized.

The selection of fan location largely dictates the choice of fan. A wet fan is required for handling gases at saturated conditions; whereas, a dry fan is applicable for handling gases at temperatures above the dew point. Since the gas temperature is about 310° F at the entrance to the scrubbers, a dry fan is applicable for the first location. Because of the higher gas temperature prior to gas humidification and cooling this fan would handle the largest volumetric flow. The gas at the second location is saturated and a wet fan would be required. At the third location, placement of the fan upstream of the reheater would require a wet fan, whereas downstream locations can utilize the dry type. Use of a dry fan after reheat requires a fan with a somewhat higher volumetric capacity, but this location is generally considered to be the most desirable. Although smaller quantities of particulates are present in the gas to cause erosion at this location, deposition of entrained solids may be a problem.

A dry fan installed downstream of the flue gas reheater is assumed for this study. Use of a dry fan agrees with the current TVA selection for the 550-mw Widows Creek limestone scrubbing installation.

The type of installation (new or retrofit) and the type of power plant, (coal- or oil-fired) largely dictates the design specifications for the flue gas system. New power plant installations can be designed to utilize one I.D. fan for each duct to overcome the draft losses both in the boiler and in the scrubbing system. However, for retrofit installations the existing I.D. fan is not capable of overcoming the pressure drop in the scrubbing system, and an additional fan is required. The pressure drop encountered in oil-fired installations is less than for coal-fired because oil-fired systems do not include particulate scrubbers. The pressure drop distribution shown in table 22 is assumed for specification of the fans and determination of resulting operating costs for Schemes A, C, and D installations on coal- and oil-fired power units. Pressure drop in the Grillo designed spray scrubber is understood to be only 2.2 in.; therefore, for Scheme B cases, the applicable pressure drops are adjusted downward by 2.3 in.

Slurry or Solution Processing

Each of the magnesia schemes is based on the formation of magnesium sulfite with a minimum amount of oxidation to sulfate and subsequent separation from the absorbent liquor by further processing. In Schemes A, B, and D crystalline magnesium-sulfur compounds are formed directly in the circulating slurry and the precipitated solids are recovered from the scrubber effluent for further treatment. In Scheme C, the clear liquor variation, the absorbed sulfur dioxide is present in the effluent as a solution of magnesium compounds in a fly ash slurry, and additional steps are required for separation of fly ash and solution and reaction of clarified solution with magnesia to increase the pH and precipitate the magnesium compounds. The precipitated compounds can then be processed to obtain a crystalline cake for feed to the dryer in the same manner as used in the other three schemes.

Slurry or solution processing can be subdivided into the following three functions:

1. Contamination control.
2. Hydrate conversion.
3. Solid-liquid separation.

Contamination control is required to reduce the amount of impurities which will accumulate in the closed loop sulfur dioxide absorber liquor. At this time little data are available to define the magnitude and exact method for control of the contaminants; however, this information should become available after extended operation of the Boston Edison demonstration system during 1972-73.

Both soluble and insoluble impurities are introduced into the sulfur dioxide absorber. As indicated in the Process Chemistry, Properties and Kinetics section of the report, the majority of the soluble contaminants enter the system in the makeup water. Additional soluble impurities from makeup MgO are introduced in much smaller quantities into the absorber. Based on the impurity data given, a new 500-mw power unit burning coal containing 3.5% S introduces soluble contaminants into the sulfur dioxide absorber liquor at the rates shown in table 23.

Insoluble contaminants are introduced into the sulfur dioxide absorber chiefly as fly ash. For the slurry schemes (A, B, and D) applied to coal-fired power units, approximately 1% of the fly ash emitted from the boiler is in the gas at the inlet to the sulfur dioxide absorber. Even though particulate scrubbers are not provided for oil-fired units, quantities of fly ash in the gas to the sulfur dioxide absorber would be smaller than for coal firing. For the clear liquor scheme, all of the fly ash emitted from the boiler is introduced into the sulfur dioxide absorber. Table 24 indicates the rates of introduction for new 500-mw units. Although not all of this fly ash will be collected in the circulating liquor, the values indicate the potential magnitude of contamination.

It can be seen that the rate of input for insoluble impurities is much greater than for soluble contaminants.

Equipment requirements for removal of contaminants can not be well defined until operating results are available. Because of differences in input rate of insoluble impurities and the form in which the sulfur compounds exist,

Table 22. Assumed pressure drop through gas system in H_2O.

Type unit	Boiler	Particulate scrubber	SO_2 scrubber	Reheater	Duct	Total
Coal–new	15	8.5	4.5	2.0	8.0	38.0
Coal–existing	–	8.5	4.5	2.0	8.0	23.0
Oil–new	15	–	4.5	2.0	4.0	25.5
Oil–existing	–	–	4.5	2.0	4.0	10.5

Table 23. Introduction rate of soluble contaminants into sulfur dioxide absorber.

Major soluble contaminant	Soluble contaminant rate, lbs/hr		
	From makeup MgO	From makeup H_2O	Total
Calcium oxide, CaO	0.040	1.156	1.196
Sulfate ion, $SO_4^=$	0.008	0.421	0.429
Chloride ion, Cl^-	0.007	0.281	0.288
Total major soluble contaminant	0.055	1.858	1.913

Table 24. Introduction rate of fly ash into sulfur dioxide absorber.

	Fly ash rate, lb/hr
Slurry schemes, coal fired	337
Slurry schemes, oil fired	243
Clear liquor scheme, coal fired	33,700

different contaminant control procedures are required for slurry and clear liquor schemes.

For the slurry schemes, equipment can be provided for reacting a portion of the slurry with sulfur dioxide in a solubilizing tank, followed with removal of the fly ash by filtration and disposal of the cake. Fresh MgO can be added to the filtrate in an agitated reactor to reprecipitate the magnesium compounds. These solids can be recovered from the slurry by filtration, and returned to the scrubbing loop, with the filtrate containing soluble contaminants discarded to an evaporative pond.

For the clear liquor scheme, a considerable amount of fly ash is present in the scrubber effluent and a thickener is necessary for sedimentation. Since the sulfur compounds in the effluent are soluble, a solubilizing tank is not required prior to removal of fly ash. Fly ash is filtered from the thickener underflow, sluiced with water, and then disposed. A bleed stream of the filtrate is treated to remove the soluble impurities as described for the slurry schemes.

Pilot plant data for MgO slurry scrubbing indicate that $MgSO_3 \cdot 6H_2O$ may be the predominant sulfite species present in the effluent from the sulfur dioxide absorber. Further test work presented in the Process Chemistry, Properties and Kinetics section indicates that $MgSO_3 \cdot 3H_2O$ can be obtained from the hexahydrate by simple thermal conversion. Since the heat required for drying the latter species is less than that required for drying $MgSO_3 \cdot 6H_2O$, an economic evaluation is desirable to determine which material should be fed to the dryer. Two process alternatives were considered. The first alternative provides for dewatering the scrubber effluent to obtain a cake primarily composed of hexahydrate crystals, followed by drying. The second alternative requires thermal conversion of a thickened hexahydrate slurry to obtain the trihydrate material, followed by dewatering as in the first method, and drying.

Dewatering and drying of hexahydrate crystals can be performed satisfactorily (12); however, no test results are available for dewatering and drying of trihydrate crystals. As discussed in the Process Chemistry, Properties and Kinetics section, trihydrate crystals are likely to be much smaller than the hexahydrate form and dewatering could be more difficult. For purposes of evaluation, a trihydrate cake was assumed to contain approximately 15% free moisture as compared to 5% for a hexahydrate cake.

Although additional equipment and heat are required to convert the hexahydrate crystals to the trihydrate form and to evaporate the additional free moisture in the cake, a considerable heat savings is obtained in the dryer. The total heat requirements of the two alternatives are indicated in table 25 for a new, 500-mw, 3.5% S, coal-fired unit. The heat required for thermal conversion is based on a concentrated slurry since data presented earlier show thickened slurries to have the fastest conversion rates and require less sensible heat. This net heat savings was applied in the dewatering evaluation to follow.

The several solid-liquid separation alternatives were considered for concentrating the slurry prior to drying as indicated in table 26.

Chemico-Basic has tested direct centrifugation (alternative 1) of the scrubber effluent for the $MgSO_3 \cdot 6H_2O$ process and found this to be a satisfactory operation. Their work indicates that a centrifuge cake containing about 5%

Table 25. Heat requirements of alternative dewatering-drying processes.

	$MgSO_3 \cdot 6H_2O$ process	$MgSO_3 \cdot 3H_2O$ process
Heat required for conversion, million Btu/hr	–	10
Heat required for drying, million Btu/hr	70	48
Total heat required, million Btu/hr	70	58

Table 26. Solid-liquid separation alternatives.

$MgSO_3 \cdot 6H_2O$ process concentrating methods	$MgSO_3 \cdot 3H_2O$ process concentrating methods
1. Centrifuge	1. Thicken, convert, then centrifuge
2. Thicken, then centrifuge	2. Thicken, convert, then filter
3. Filter	
4. Thicken, then filter	

free moisture can be obtained. Since thickening of the effluent slurry from the sulfur dioxide absorber can reduce the volumetric feed rate of the slurry, a thickener and centrifuge alternative was also considered (alternative 2).

A third alternative, filtration, was considered for concentrating the slurry. However, based on equipment costs, filtration equipment vendors do not recommend filtration of dilute slurries.

After prior thickening, filtration should be a practical alternative (alternative 4). Test work on filtration of $MgSO_3 \cdot 6H_2O$ slurries has not been reported; however, equipment vendors indicate that the filter cake would contain between 10 and 20% free moisture. A somewhat higher capacity dryer would be required for operation with a filter compared to a centrifuge to compensate for the additional free moisture content.

Gravity thickeners and wet screens were considered for thickening the solids in the scrubber effluent. Experience in the chemical industry has shown gravity thickening to be a reliable and relatively inexpensive way to increase the solids concentration of a slurry. The primary equipment required for this operation includes a conical bottom settling tank, a thickener rake with drive and supports, and slurry pumps for pumping the thickened underflow. The size of the equipment is dependent upon the settling rate of the solids. Laboratory tests were made at TVA to determine the concentration of solids to be expected in the underflow from a gravity thickener and the parameters which affect the settling rate of the crystals. The data indicate that the crystals settle to form a slurry containing about 50-60% solids. It was also found that the settling rate of the solids is dependent upon the concentration of magnesium sulfate in the solution phase, but relatively independent of the temperature of the slurry. Figure 53 shows the relationship between time and solution-slurry interface for $MgSO_3 \cdot 6H_2O$ settling through saturated solutions containing soluble $MgSO_4$; the rate of settling of $MgSO_3 \cdot 6H_2O$ is more rapid for slurries with low concentrations of soluble $MgSO_4$.

Wet screens are utilized in industry for dividing a slurry into two streams:

1. A dilute slurry containing the smaller size crystals.
2. A concentrated slurry containing the larger size crystals.

Since fine solids are recycled to the scrubbing loop, satisfactory operation of these devices for the MgO schemes depends upon crystal growth rather than new crystal formation in the absorption loop. If crystalline growth is satisfactory, these devices can be used in place of gravity thickeners. Since they do not require the large tank provided for the gravity thickener alternative, the investment for these devices is less.

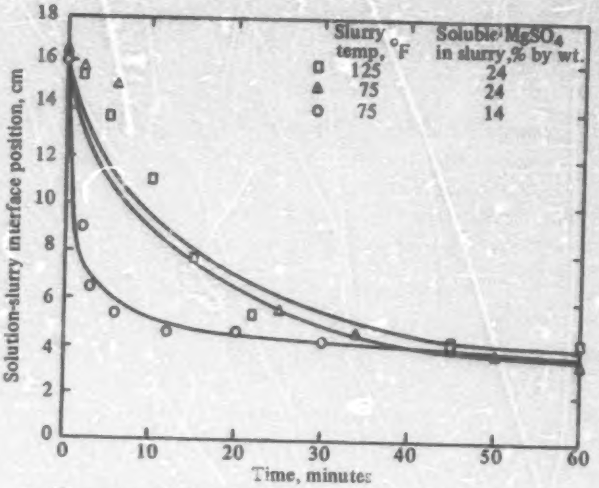

Figure 53. Effect of time on solution-slurry interface position for crystalline $MgSO_3 \cdot 6H_2O$ settling through saturated $MgSO_3 \cdot 6H_2O$ solutions containing soluble $MgSO_4$.

Chemico-Basic has recently tested the use of wet screens for the 150-mw prototype installation at Boston Edison's Mystic No. 6 power plant and found their performance to be satisfactory. Table 27 below shows comparative equipment costs for a gravity thickener and a wet screen. In addition to having a favorable cost advantage, the wet screen devices require less space than gravity thickeners, which itself would be adequate basis for selection for some power plant locations. Wet screens were selected for thickening the effluent from the scrubbers. Underflow pumps are not required for the wet screen type thickener because the screens can be elevated to discharge directly into the conversion tank.

Prior to obtaining final cost data, a preliminary economic evaluation of $MgSO_3 \cdot 6H_2O$ and $MgSO_3 \cdot 3H_2O$ dewatering methods was made. Since the filtration alternatives require more heat for drying than do the centrifuge alternatives, both the concentrating and drying steps were considered. Table 28 shows the estimated equipment investment, operating horsepower, dryer heat requirements, and annual operating costs for the $MgSO_3 \cdot 6H_2O$ process dewatering alternatives. Although alternative 4 requires the

Table 27. Approximate equipment investment requirements for thickening, $.

	Gravity thickener	Wet screens
Thickener and drive	25,000	–
Thickener tank including lining	85,000	–
Wet screens	–	20,000
Liquor tank	10,000	10,000
Liquor pumps	4,000	4,000
Underflow pumps	2,000	–
Subtotal–equipment	126,000	34,000

Table 28. Comparison of various $MgSO_3 \cdot 6H_2O$ dewatering alternatives.

Dewatering method	1 Centrifuge dry	2 Thicken centriguge dry	3 Filter dry	4 Thicken filter dry
Estimated equipment investment, M$	1,320	1,150	–	1,110
Operating horsepower	1,590	1,410	–	1,270
Dryer heat requirement, million Btu/hr	70.1	70.1	–	81.1
Annual operating cost including capital charges, M$/yr	812	772	–	816

lowest investment and horsepower, a greater amount of heat is required for this alternative. Based on the above annual operating costs, thickening followed by centrifugation (alternative 2) appears to be the most economical dewatering alternative and was selected for the $MgSO_3 \cdot 6H_2O$ process.

For concentrating $MgSO_3 \cdot 3H_2O$ slurry, alternative 1, indicated earlier (thicken, convert, and centrifuge), was selected since the smaller trihydrate crystals would be harder to filter than the hexahydrate crystals; therefore, the centrifuge alternative should be more economical.

A comparison of the estimated total dewatering requirements for the $MgSO_3 \cdot 6H_2O$ and $MgSO_3 \cdot 3H_2O$ processes is given in table 29.

Based on a fuel oil cost of $0.09/gal ($0.60/million Btu), and an annual operating rate of 7,000 hrs/yr, the net heat savings when using the $MgSO_3 \cdot 3H_2O$ as opposed to the $MgSO_3 \cdot 6H_2O$ process amounts to a fuel cost savings of approximately $50,400/yr. The remaining operating cost difference is the result of the lower equipment investment and operating horsepower required for the $MgSO_3 \cdot 3H_2O$ process.

Sulfite Drying—Calcining

Regeneration of magnesia from a wet cake feed involves drying the feed to remove the free and combined moisture, and calcination to regenerate magnesia and release gaseous sulfur dioxide at concentrations necessary for production of sulfuric acid. Drying and calcining can be performed either separately or in a single combined device. Although a combined dryer-calciner probably can be designed for more efficient heat utilization, the greater amount of heat required for the combination unit to provide for both drying and calcining results in an offgas containing low concentrations of sulfur dioxide. In addition, the high moisture content of the feed cake to a combination unit results in higher concentrations of moisture in the offgas. The combined effects would make it more expensive to produce 98% H_2SO_4. By providing separate facilities for drying and calcining, the amount of moisture in the feed to the calciner and the amount of combustion gas in the calciner can be reduced to more desirable levels for 98% H_2SO_4 production; therefore, separate drying and calcining units are incorporated in the process design. There is no alternative when considering off-site magnesia regeneration and H_2SO_4 production.

To improve the heat utilization of a separate drying unit, the offgas from the dryer, after dust removal, can be exhausted to the stack to supply a portion of the required stack gas reheat. The heat utilization of a separate calciner unit can be improved by providing preheating stages for countercurrent contact between offgas and incoming feed.

Operating requirements for drying, calcining, and sulfuric acid manufacture are interrelated, since any moisture contained in the solid discharge from the dryer is transferred to the calciner offgas, which is fed to the sulfuric acid unit. Because of this relationship, the effect of moisture content of the feed to the calciner on the sulfuric acid process was studied. The results are discussed below and are based on calcination by direct combustion of a No. 6 fuel oil with 5% excess air.

Table 29. Comparison of $MgSO_3 \cdot 6H_2O$ and $MgSO_3 \cdot 3H_2O$ dewatering processes.

Process	$MgSO_3 \cdot 6H_2O$ (thicken-centrifuge) dry	$MgSO_3 \cdot 3H_2O$ (thicken-convert-centrifuge) dry
Estimated equipment investment, M$	1,150	998
Operating horsepower	1,410	1,250
Converter heat requirement, million Btu/hr	–	10
Dryer heat requirement, million Btu/hr	70	48
Annual operating cost including capital charges, M$/yr	772	666

Figure 54 shows the relationship between the moisture content of the feed to the calciner and the composition of SO_2 and H_2O in the calciner offgas. The effect of moisture content of the feed to the calciner on the concentration of sulfuric acid, assuming no addition or removal of water at the sulfuric acid unit, is shown in figure 55. The moisture content of the feed to the calciner must be below 4.4% H_2O at an inlet feed temperature of 400° F to allow for production of 98% H_2SO_4 without providing extra facilities for removing water from the calciner offgas. However, supplemental water must be added at the H_2SO_4 unit to obtain 98% H_2SO_4 if the moisture content of the feed is below 4.4%. Since this appears to be the simplest method for controlling the concentration of the product acid, a calciner feed containing less than 4.4% moisture is desirable.

The effect of the temperature of the feed to the calciner on the composition of SO_2 in the offgas, and the amount of water which must be added at the sulfuric acid unit is shown in figures 56 and 57. The relationships are based on a calciner feed containing about 2.1% water and a 98% sulfuric acid rate of 16.1 tons/hr or 35.4 gal/min. These correspond to the expected product rates assuming Scheme A is applied to a new 500-mw unit utilizing coal containing 3.5% sulfur. For an off-site calcination unit with an inlet feed temperature of approximately 60° F, the required rate of addition of water for 98% H_2SO_4 manufacture is approximately 1.1 gal/min.

The equipment alternatives which were considered for drying and calcining in the magnesia scheme are shown in table 30.

In the test program performed by Grillo on the MgO-MnO_2 variation (Scheme B), spray dryers were utilized for drying the effluent slurry containing absorbed sulfur dioxide. Vendors of spray drying equipment were contacted to provide general information and cost data to aid in determining the applicability of these devices for full scale installations. Operation of spray dryers requires that the feed be pumpable; therefore, spray dryer installations must be capable of evaporating a greater amount of moisture than required for drying a centrifuge cake. The additional moisture in the feed increases the dryer heat requirement considerably. For base case conditions, the heat requirement for a spray dryer installation is in the range of 150-175 million Btu/hr. This compares with an estimated heat requirement of about 70 million Btu/hr for drying a centrifuge cake composed primarily of $MgSO_3 \cdot 6H_2O$ and about 58 million Btu/hr for conversion of $MgSO_3 \cdot 6H_2O$ to $MgSO_3 \cdot 3H_2O$ followed by drying. From discussions with vendors of spray dryers, it appears that these devices are generally used for drying heat sensitive materials or for other special applications. Also, a larger capital investment is required for these devices. For the magnesia schemes, other types of dryers appear to be more practical; therefore, spray dryers were not selected.

Table 30. Dryer-calciner equipment alternatives.

Dryer alternatives	Calciner alternatives
1. Spray	1. Rotary
2. Entrainment	2. Fluid bed
3. Rotary	
4. Fluid bed	

In entrainment dryers, the feed to the dryer is entrained in the carrier gas and is dried in passing through the system. Although this method of drying appears to be feasible, vendors declined to estimate the costs of these systems without first performing tests. They indicate that satisfactory operation requires a relatively free-flowing feed, which may necessitate recycle of dryer product to mix with the centrifuge cake. Actual tests are required to determine the amount of recycle to provide before design and costs can be determined. In addition, a lower inlet gas temperature is required for entrainment dryers because of the high gas requirements for conveying the solids. Since cost data was not made available, these devices were not included in the design.

Both rotary and fluid bed systems appear to be feasible for drying and calcining. Chemico-Basic has tested a rotary system for drying a $MgSO_3 \cdot 6H_2O$ centrifuge cake; products containing about 3% moisture were obtained when the feed was dried to temperatures of 600-800° F. Although oxidation data is not available, Chemico-Basic recommends drying with a minimum amount of excess oxygen in the gas to prevent excessive conversion of $MgSO_3$ to $MgSO_4$.

Chemico-Basic has also tested a rotary calciner for regeneration of magnesia. The tests showed that essentially complete regeneration from magnesium sulfite was obtained at calcination temperatures of 1600-2000° F with the addition of coke to produce a reducing atmosphere in the calciner.

Although very little data are available for either drying or calcining in fluid bed equipment, these devices have advantages over rotary systems, including lower investment and operating costs, better temperature control, lower heat losses, and less space requirements. Because of better contact between the solid and gas phases, these devices should be capable of obtaining high calcination efficiencies at lower temperatures (1400-1800° F) than required for rotary equipment. Tests performed in Japan with regeneration of the MgO-MnO_2 material indicates a fluid bed system performed satisfactorily at 1800° F without reducing coke. With reductant, lower temperatures should be feasible.

Based on vendor quotations, estimated investment and operating costs for rotary and fluid bed dryers and calciners are given in table 31 for a coal-fired, base case installation. Rotary equipment was assumed to require about 10% more

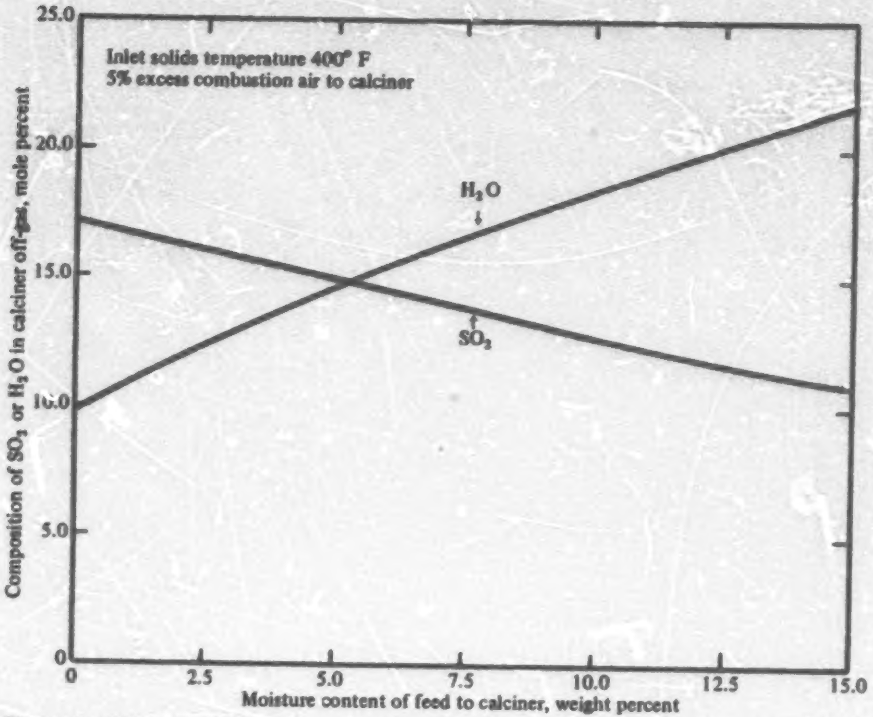

Figure 54. Effect of moisture content of feed to calciner on composition of calciner offgas.

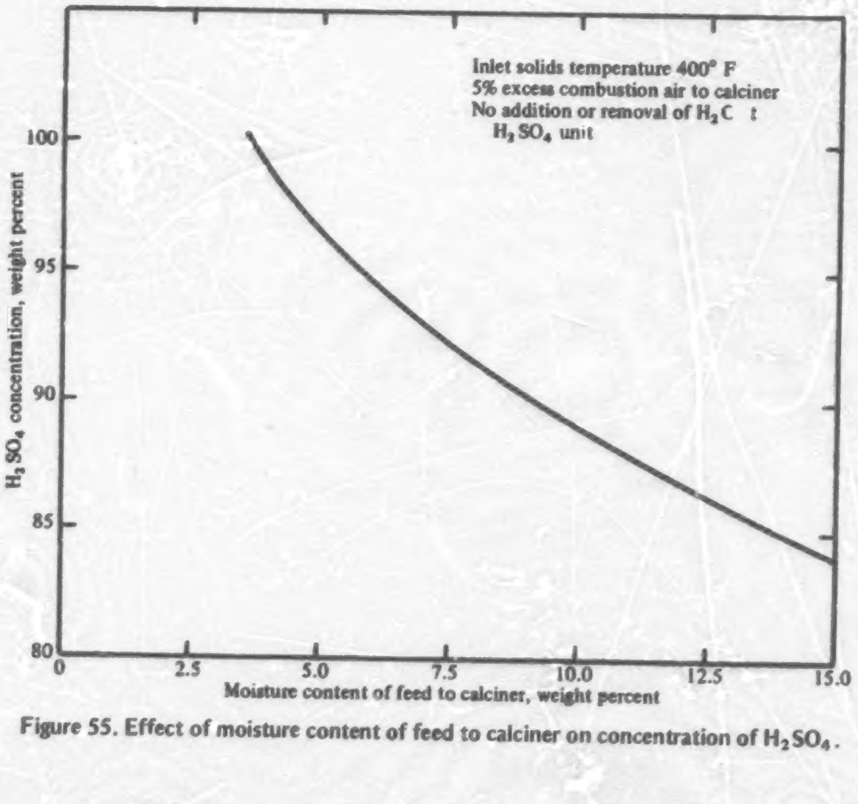

Figure 55. Effect of moisture content of feed to calciner on concentration of H_2SO_4.

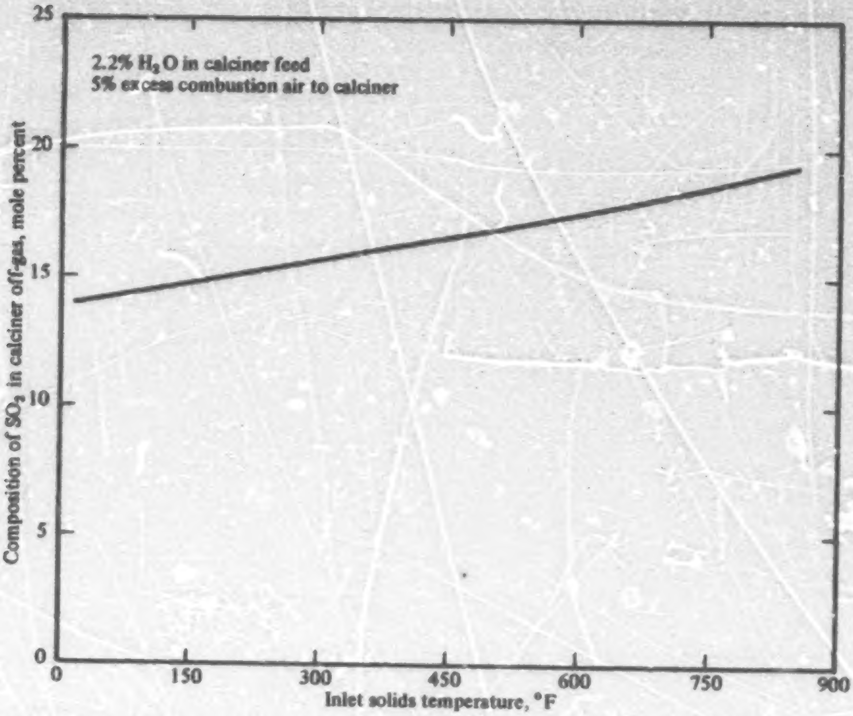

Figure 56. Effect of inlet solids temperature to calciner on composition of SO_2 in calciner offgas.

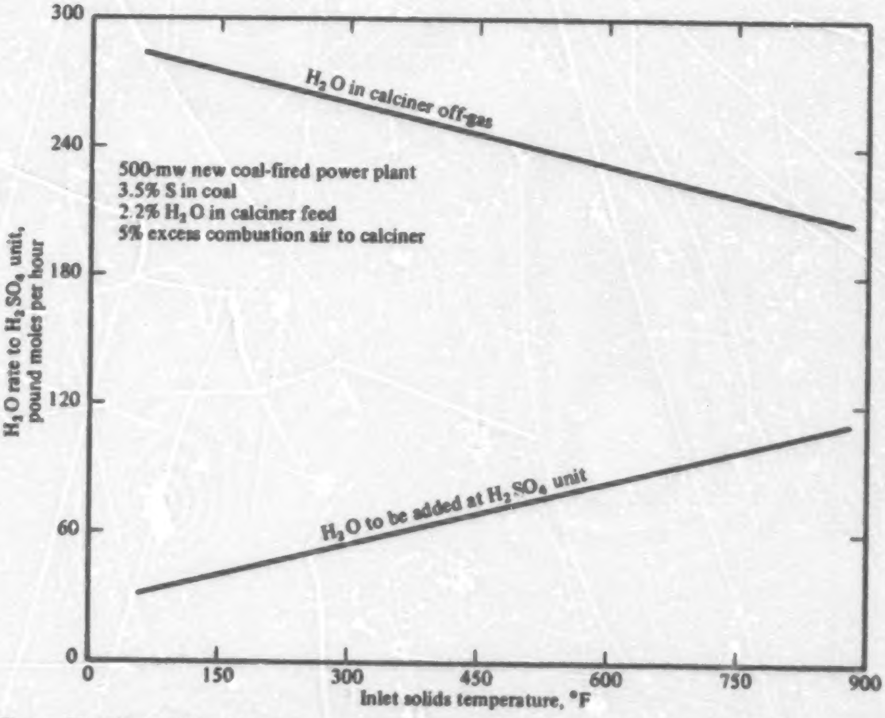

Figure 57. Effect of feed temperature of solids to calciner on H_2O requirement at H_2SO_4 unit.

Table 31. Estimated investment and operating costs for rotary and fluid bed dryers and calciners for base case installation.

	Rotary		Fluid bed	
	Dryer	Calciner	Dryer	Calciner
Total investment, M$	740	1,475	635	845
Operating horse-power	600	750	450	400
Heat required, million Btu/yr	420,000	459,000	381,000	417,000
Annual operating cost including capital charges, M$/yr	571	792	510	593

heat to compensate for additional losses due to the larger equipment size.

Fluid bed equipment was selected for drying and calcining for the various magnesia schemes because of the estimated lower overall operating costs.

The Boston Edison demonstration scale unit incorporates rotary dryers and calciners for regeneration of magnesia, although Chemico-Basic and others generally agree that fluid bed regeneration will be the most attractive alternative for future installations. The rotary system was selected for the 155-mw demonstration installation because all test data were obtained for rotary equipment and timing did not permit further testing on fluid bed devices.

Cyclone dust collectors are normally provided for primary collection of dust from the offgases of fluid bed dryers and calciners. Generally, these devices are not capable of achieving removal efficiencies as high as required for the magnesia applications; therefore, secondary dust control is necessary to obtain overall removal efficiencies of 99.5%. The following acceptable alternatives for secondary dust control were considered:

1. Wet scrubbers
2. Bag filters
3. Electrostatic precipitators

Wet scrubbers are capable of high dust removal efficiencies with relatively low investment; however, these devices result in humidification of the offgas preventing effective heat utilization. Bag filters are capable of high dust collection efficiencies without reducing heat utilization, but the temperature of the gas is limited to 425-500° F to prevent destruction of the fabric bags. Electrostatic precipitators also are capable of high dust collection efficiencies without loss in utilization of heat, but their capital cost is higher. However, these devices can operate over a wider range of temperatures than bag filters.

With a dryer offgas temperature of about 400° F, either a bag filter or an electrostatic precipitator could be effectively utilized. For the fluid bed calciner, the temperature of the offgas is expected to be 1400-1800° F, and gas cooling is necessary if a bag filter is to be used.

Since more efficient overall heat utilization can be obtained in the calciner by providing a waste heat boiler in the offgas stream, this provision, under proper design conditions, permits use of either a bag filter or an electrostatic precipitator for cleaning the calciner exhaust gas.

The estimated investment and operating costs for wet scrubbers, bag filters, and electrostatic precipitators for cleaning the dryer exhaust are given in table 32 for a coal-fired, base case installation. These costs are based on an inlet gas rate to the dust collector of about 57,900 acfm at 400° F. Based on these results, wet scrubbing is not economically feasible for controlling dust emissions from the offgas. Although the investment required for this method is lower than for the other methods, the net operating costs are higher due to the high utility requirements and loss of heat utilization. There is little difference in the operating costs of either bag filters or electrostatic precipitators. Bag filters require a somewhat smaller initial investment, but have higher projected utility and maintenance costs. As mentioned previously, TVA operating experience with electrostatic precipitators for fly ash removal has shown that high collection efficiencies are difficult to maintain over long periods of time. Since any reduction in dust removal from the calciner offgas introduces additional undesirable contaminants into the sulfuric acid unit, bag filters appear to be the more satisfactory devices for maintaining high dust removal efficiencies; therefore, these devices are chosen for all four schemes. It might be mentioned that Chemico-Basic has selected bag filters for the Rumford, Rhode Island, demonstration calcining plant. These devices appear to be more practical for cleaning small volumes of gas as encountered in drying and calcining; however, for larger volumes electrostatic precipitators may be the better choice.

Table 32. Estimated investment and operating costs for control of dust emissions from the dryer for base case installation.

	Wet scrubber	Bag filter	Electrostatic precipitator
Total investment, M$	182	207	225
Utility requirements, $/yr	12,000	3,200	1,900
Heat loss, $/yr	39,500	0	0
Maintenance, $/yr	7.300	7,000	6,000
Capital charges. $/yr	27,100	30,900	33,500
Annual operating cost, $/yr	85,900	41,100	41,400

Because of the potential for reaction of sulfur oxides, air, and water in the calciner offgas, and possible condensation of H_2SO_4 mist, the temperature of this gas must be controlled carefully. Since some additional cooling occurs with the addition of supplemental air required for conversion of SO_2 to SO_3, the waste heat boiler is designed to cool only to 700° F so that gas temperature remains above the dew point of the acid after the supplemental air is added. This air is added between the waste heat boiler and the bag filter; at low concentrations of SO_3 in the gas, the resulting 400° F final temperature should insure satisfactory operation of the bag filter without condensation of acid mist.

Sulfuric Acid Production

Most of the sulfuric acid production facilities built in the last decade utilize the contact process in which the following steps, in order, take place (28):

1. The generation of a sulfur dioxide-containing gas from an appropriate raw material.
2. The cooling (if necessary), purification, and drying of the sulfur dioxide-containing gas.
3. Reheating of the sulfur dioxide-containing gas to the proper temperature for conversion to sulfur trioxide.
4. Catalytic oxidation of the sulfur dioxide to sulfur trioxide.
5. Cooling of the sulfur trioxide-containing gas.
6. Production of sulfuric acid by absorption of the sulfur trioxide in concentrated sulfuric acid.

Many of these steps are independent of the source of sulfur dioxide; however, others are dependent on the composition of the carrier gas. Because of the water content of the feed to the calciner and the water formed during combustion of the fuel for calcination, the offgas from a magnesia regeneration unit contains more moisture than a conventional gas from a sulfur burner and must be dried prior to SO_3 conversion. Table 33 shows the estimated overall composition of feed gas to the sulfuric acid unit for a $MgSO_3$ calciner offgas, and a sulfur burner offgas. For comparison, each of these compositions includes the required amount of bleed air to result in an O_2:SO_2 mole ratio of 1.4 as required for efficient conversion of SO_2 to SO_3.

Table 33. Estimated composition of feed gas to sulfuric acid unit.[a]

Type gas	Overall composition, mole %					
	N_2	CO_2	O_2	H_2O	SO_2	Total
$MgSO_3$ calciner offgas[b]	68.67	5.71	10.92	6.90	7.80	100.00
S burner offgas	77.33	–	11.99	2.11	8.57	100.00

[a] Excluding CO, SO_3, and other compounds wich may be present.
[b] Based on a calciner feed containing 2.2% H_2O.

As mentioned in the previous section, several alternatives are available for cleaning the feed gas to the sulfuric acid unit. Generally, these are described either as "wet" or "dry" dust removal systems, and the selection of the type to be included is closely related to design of the acid unit. Although more design and operating experience is available for the wet type, certain advantages are inherent in both systems.

The main advantage of "dry" gas cleanup systems over "wet" is the ability of these systems to clean the gas without lowering the temperature. Since the gas must be heated to high temperatures (about 830° F) prior to entering the converter, better heat utilization is obtained. However, dry systems do not offer a practical way for removing moisture from feed gases when required. Production of 98% H_2SO_4 requires an overall mole ratio of H_2O:SO_2 in the feed of about 1.11. At lower mole ratios, water must be added to the system, whereas higher ratios require removal of moisture for producing the high strength acid. Condensation of water from the gas by cooling below the saturation temperature appears to be the most practical way to reduce the water content of the gas. If this is required, a wet scrubber would be the simplest device for cooling the gas and, because of its dual role of both cleaning and cooling, would become the most practical alternative.

Cooling the feed gas to a sulfuric acid unit to allow for production of high strength acids is practical and done routinely with metallurgical SO_2 offgas. The offgas of a separate calciner unit can be controlled to adequate moisture contents to allow for production of 98% H_2SO_4; however, the moisture content of the offgas of a combination dryer-calciner can not be reduced enough by wet scrubbing alone to allow for production of a concentrated acid. The larger quantity of gas contains more moisture than required even at saturated conditions at the scrubber operating temperature. Based on discussions with vendors, it does not appear to be desirable to design an acid unit for producing a dilute acid. This type unit would introduce special problems including:

1. More difficult acid mist control because it is harder to collect H_2SO_4 mist than to absorb SO_3, especially in lower strength acids.
2. More expensive materials of construction due to the higher corrosiveness of weaker acids.
3. Larger facilities for storing a dilute acid.
4. More expensive heat exchangers.
5. Additional expense in shipping the more dilute acid.
6. Lower sales price for dilute acid.

Because of the above production of dilute acids was not considered to be an economical alternative, and further evaluation of combination dryer-calciner units was not pursued.

Since the separate unit selected for drying the centrifuge cake is designed to obtain a high water removal efficiency, either a "wet" or a "dry" sulfuric acid process is feasible. Estimated investment and operating cost for both acid processes are shown in table 34. Although investment data were obtained from several vendors, for uniform comparison of wet and dry system costs, only one set of data is shown.

Based on the estimated lower costs, a dry sulfuric acid system was selected for incorporation in the various magnesia schemes. Although this type system requires higher drying efficiencies for producing 98% H_2SO_4 than the wet system, as discussed previously, the higher efficiencies appear to be attainable.

High degrees of contamination control are desirable in the sulfuric acid unit to prevent fouling of converter catalyst. It appears that a dry sulfuric acid process utilizing a bag filter for dust removal will provide sufficient control for maintaining activity of the catalyst over long periods.

In addition to defining the emission standards for power generating plants, the EPA has also defined emission standards for various chemical processes including those shown in table 35 for sulfuric acid plants (29).

Based on these standards, sulfuric acid plants are required to convert a minimum of 99.7% of the inlet sulfur dioxide to sulfuric acid. A typical single absorption contact plant is capable of attaining an SO_2 recovery efficiency of about 97%. Since this does not meet the EPA standards for emission control, additional facilities are required for reducing the sulfur dioxide content of the tail gas. A tail gas system capable of a recovery efficiency of 90% in conjunction with a 97% efficient contact plant will provide an overall sulfur dioxide recovery efficiency of 99.7% which meets the emission standards. In the design of on-site sulfuric acid units, the tail gas is cycled back to the stack gas absorber to increase overall recovery efficiencies.

For off-site sulfuric acid units, this can not be done; therefore, the following alternatives were considered:

1. Utilize a double absorption sulfuric acid process which achieves higher SO_2 conversion and absorption efficiencies.
2. Utilize a wet scrubbing process for absorbing SO_2 from the sulfuric acid unit tail gas.

Table 34. Estimated fixed investment and operating costs for "wet" and "dry" sulfuric acid units for base case installation.

Type of gas cleanup system	Wet	Dry
Total fixed investment for acid plant including calciner gas cleanup system, M$	4,364	3,650
Annual operating cost including capital charges, M$/yr	1,267	1,107

Table 35. Environmental Protection Agency emission standards for sulfuric acid plants.

	Allowable emission, lb/ton of H_2SO_4
Sulfur dioxide	4.0
Sulfuric acid mist	0.15

It is not certain that the first alternative can achieve an overall absorption efficiency of 99.7%; therefore, this alternative was not selected. There are several tail gas scrubbing processes which appear to be capable of meeting emission requirements including limestone scrubbing, sodium salt scrubbing, and magnesium oxide scrubbing. Although the merits and costs of these processes were not compared, an MgO tail gas scrubbing system was selected and incorporated into the design of the tail gas cleanup system. This alternative requires that a centrifuge and dryer system be provided at the off-site calcination unit to dewater and dry the scrubber effluent prior to its introduction into the calciner; however, it is the most compatible alternative with magnesia scrubbing of power plant stack gas.

During the procurement of cost and design data for sulfuric acid units, some vendors recommended the use of fluorocarbon heat exchangers and acid pump tanks in the sulfuric acid plant. Although the costs of these systems were said to be less than the costs of more conventional cast iron units, the only acid plant prices received were based on conventional heat exchange systems. For purpose of this report, the flow diagrams, equipment costs, and layout drawings presented will reflect only the cast iron type exchangers. It should be recognized that fluorocarbon heat exchange systems are potential money savers if conditions permit their utilization.

Materials of Construction

One of the most important design considerations for the magnesia scrubbing-regeneration process is the specification of appropriate materials of construction for the equipment, piping, and ductwork to minimize operational failures and maintenance costs due to corrosion and erosion. Materials of construction are particularly important for stack gas slurry scrubbing applications because of the potential for excessive erosion. In addition, the various process operations and material properties require different protective measures.

Very little actual quantitiative data is available at this time to indicate the most desirable materials of construction for the various operations in the magnesia schemes; however, some guiding information was obtained from the following sources:

1. Sulfite pulping applications in the paper industry.
2. Babcock and Wilcox pilot plant tests (27).
3. Chemico-Basic pilot plant tests (12).
4. Grillo pilot plant tests (61).

5. TVA pilot plant and laboratory tests of various gas scrubbing systems.

6. Vendor recommendations.

In an attempt to obtain more complete corrosion data for the magnesia systems, some static corrosion tests were performed by TVA; however, the results were not quantitative because the conditions expected in actual operation were not simulated for sustained periods of time. The pH of the slurries in contact with the various test specimens changed during the tests and the effect of prolonged contact at a given pH could not be determined. In addition, the effect of erosion is not obtained using static tests. It is expected that the Boston Edison prototype demonstration unit will provide corrosion and erosion data from extended periods of operation under actual dynamic conditions; this information will be helpful in designing actual installations.

In this conceptual design, scrubber shells are constructed of mild steel except in areas with high gas velocities which should be of alloy steel. The scrubber shells are lined with rubber or a plastic coating. Surge tanks, pumps, agitators, and slurry piping in the scrubbing area are constructed of rubber-lined carbon steel. Following current practices, ductwork between the powerhouse and the scrubbers is Corten. Ductwork between the scrubbers and the stack gas reheater system is epoxy-lined mild steel. The I.D. fan and the ductwork between the reheater and the stack are Corten since these areas require some protection from reheater failure. The direct reheat system is constructed of plain carbon steel with firebrick insulation for the areas exposed to extremely high temperatures. If a tubular, indirect steam, reheater is used, it should be made of alloy steel.

In the slurry processing area, the wet screens, conversion tank, conversion tank heating coil and agitator, and the centrifuges are constructed of stainless steel. The liquor tank and pumps are rubber-lined mild steel, and the steam condensate tank and pumps are carbon steel. All piping in this area is rubber-lined mild steel except the piping associated with the condensate tank which is carbon steel. Wetted parts of the centrifuge include protection against abrasion with hard-surfacing and vendor-recommended abrasion-resistant materials.

The conveyor and elevator for feeding wet centrifuge cake to the dryer are constructed of carbon steel. The combustion chamber, dryer, $MgSO_3$ surge bin, calciner, and the cyclone dust collectors are constructed of carbon steel with the firing end of the dryer being refactory lined. The coke storage silo, conveyors, and elevators in the dryer-calciner area are constructed of mild steel. The bag type dust collectors include mild steel housings with either Nomex or Teflon bags. Fans and ducts in the dryer-calciner area are constructed of mild steel except for high temperature service. For gas temperatures above 1100° F the ducts should be lined with brick. The waste heat boiler is constructed of mild steel.

For the magnesia preparation areas, all unloading, conveying and storage facilities are constructed of mild steel. However, the slurrying tank, agitator, slurry pumps, and MgO slurry piping system are rubber-lined mild steel to provide protection from abrasion. Off-site storage facilities for fuel oil are constructed of mild steel and are insulated.

Downstream from the calciner gas cleanup system, the sulfuric acid plant is constructed of conventional materials. Since no new technology is introduced for sulfuric acid manufacture, and a variety of different designs are available for acid units, the materials of construction for the acid plant will not be discussed. It will be mentioned, however, that the high strength sulfuric acid can be stored at low temperatures in plain carbon steel tanks.

Equipment Description

A process control diagram describing instrumentation requirements for Scheme A is shown in figure B-9 (Appendix B); although not presented, control diagrams for the other schemes are similar. A typical pilot plan representing area requirements for a new 500-mw coal-fired power unit equipped with a magnesia slurry scrubbing-regeneration system is shown in figure B-10.

Gas scrubbing and reheat—Because of air preheater design, large power plants normally include multiple gas ducts between the powerhouse and the stack. For the current study, it was assumed that 200-mw power units are designed with two gas ducts, whereas 500-mw and 1000-mw units are designed with four ducts. Each duct is fitted with a separate scrubbing system and individual scrubber bypass ducts are provided. Gas velocities of approximately 50 ft/sec are used in design of ducts.

Coal-fired power units utilizing Schemes A, B, and D are designed with separate scrubbers for particulate and sulfur dioxide control. However, coal-fired power units utilizing Scheme C and all oil-fired power units are designed with scrubbing units capable of removing both particulates and sulfur dioxide simultaneously.

In magnesia scrubbing systems, either venturi, mobile bed, or spray absorbers can be provided for sulfur dioxide absorption. A representative plan and elevation view of a two-stage venturi scrubbing installation for Scheme A applied to a new 500-mw coal-fired power plant is shown in figure B-11. A similar view of a venturi-mobile bed configuration for this scheme is shown in figure B-12. Figure B-13 shows a representative plan and elevation view of a venturi-mobile bed scrubbing installation for Scheme A applied to an existing 500-mw coal-fired power plant. The design gas flow rates through each of the four scrubber trains are shown in table 36 for new 500-mw coal-fired power units.

A representative plan and elevation view of a spray scrubbing installation for Scheme B applied to a new 500-mw oil-fired power plant is shown in Figure B-14. Each pair of parallel scrubbers on oil-fired power units (one pair per duct) is designed for an exhaust gas rate of about 238,000 acfm at 139° F.

Since the scrubbing areas of Schemes C and D are similar to the scrubbing area shown for Schemes A and B, no supplemental plans are shown for these schemes.

Table 37 gives the values of liquid to gas ratio incorporated in the design of the various scrubbers. In each scheme, entrainment separators are provided to reduce mist from the exhaust gas of the particulate and sulfur dioxide scrubbers. In the absence of better mist size definition, vendors have recommended the use of fiberglass-reinforced polyester, chevron vane type entrainment separators for mist control. This selection may or may not require modification after large scale operating experience with these and other types of devices becomes available.

For a two-stage venturi scrubbing installation applied to a new 500-mw coal-fired power plant, each scrubber is approximately 28 ft in diameter by 40 ft high. They are equipped with a conical bottom liquor sump which serves as a recirculation tank. Each particulate venturi is designed for a gas velocity of about 125-140 ft/sec. Each sulfur dioxide absorber is designed for a gas velocity of about 75 ft/sec. Agitators are not required. Liquid is recirculated to each particulate scrubber at a rate of about 4,740 gpm. The liquid circulation rate to each sulfur dioxide absorber is about 6,320 gpm. Two 200-horsepower recirculation pumps are included for each particulate scrubber, whereas each sulfur dioxide absorber is provided with two 250-horsepower pumps. Spare pumps are not provided here; during pump failure the scrubber must be operated at a reduced L/G.

Table 36. Gas flow rates through each scrubbing train, new 500-mw coal-fired units.

	Scheme A design gas flow rate at scrubber exit, acfm at 127° F
Particulate scrubber	316,000
Sulfur dioxide absorber	323,000

Table 37. Scrubber design conditions.

	L/G, gal/Macf			
Scheme	A	B	C	D
Particulate venturi scrubber[a]	15	15	[b]	15
Sulfur dioxide absorber				
Venturi	20	–	20	20
Mobile bed	10	–	10	10
Spray	–	6.0	–	–

[a] Particulate scrubbers are applicable only for coal-fired units.

[b] Particulates are removed in the sulfur dioxide absorber for Scheme C.

For venturi-mobile bed scrubbing installations applied to new or existing coal-fired power plants, both the particulate venturi and the mobile bed absorber are rectangular and are constructed adjacent to each other. They are interconnected with a common sump, separated by an entrainment separator, and designed for liquid drainage to separate recirculating tanks. Each venturi scrubber is designed for a gas velocity of about 125-140 ft/sec. Each mobile bed absorber is a two-stage, plastic sphere type and is designed for a gas velocity of about 12-13.5 ft/sec. The overall dimensions of the venturi-mobile bed scrubber configuration are approximately 32 ft wide by 25 ft long by 54 ft high. Each recirculation tank is approximately 11 ft in diameter by 16 ft high and is equipped with a 20-horsepower turbine agitator. Liquid is recirculated to the particulate scrubbers at a rate of about 4,740 gpm. The liquid circulation rate of each SO_2 absorber is about 3,160 gpm. Two 200-horsepower recirculation pumps are included for each venturi scrubber; whereas each mobile bed absorber is designed with two 125-horsepower pumps. Again, spare pumps are not provided.

For Scheme B applied to a new 500-mw oil-fired power plant, each duct is fitted with two spray absorbers connected in parallel, a total of eight. Each spray absorber is designed for a gas rate of about 45-50 ft/sec and contains three banks of spray nozzles, with four nozzles/bank. The absorbers are 8 ft by 8 ft in cross section and are approximately 48 ft high. Each pair of absorbers drains into a 7½ ft diameter by 10 ft high recirculation tank provided with a 2-horsepower turbine agitator. A separate 75-horsepower recirculating pump designed for a recirculation rate of about 825 gpm is provided for each absorber with no spares included.

Separate stack gas reheaters are provided for each power plant duct. New coal-fired units are designed with indirect steam reheaters; whereas existing coal, and both new and existing oil-fired units are equipped with direct combustion reheaters utilizing No. 6 fuel oil. Reheaters are designed to heat the gas to approximately 160° F. The additional reheat required is obtained from the dryer offgas, and the heat of compression of the gas in passing through the I.D. fan. Each duct of a new 500-mw coal-fired power unit is fitted with two parallel bare-tube heat-exchanger bundles with 550 ft^2 of heating surface each. The tube bundles are fitted into a duct approximately 12 ft by 12 ft. The design temperature profile for the steam reheaters is shown in table 38.

Radial-tip, centrifugal I.D. fans are provided for discharging the exhaust gas. As mentioned previously, new power plants are designed with one I.D. fan/duct located downstream of the reheater. The ductwork to the scrubbing

Table 38. Design temperature profile for indirect steam reheater system.

	Temperature, °F	
	In	Out
Gas (shellside)	127	160
Steam-condensate (tubeside)	470	470

area of existing power units is constructed so the existing I.D. fans can be utilized. However, supplemental I.D. fans are provided downstream of the gas reheater to supply the additional energy required to overcome the pressure drop of the scrubbing system. For a new power plant, each I.D. fan is equipped with a 2,250-horsepower motor. Each supplemental I.D. fan for 500-mw existing power units is equipped with a 1,575-horsepower motor.

Slurry or solution processing area–The liquor containing SO_2 absorbed in each scheme is pumped from the absorbers to the slurry or solution processing area for separation of solids prior to drying. In this area, full capacity spare pumps are provided.

In Schemes A and D, the slurry containing crystalline magnesium-sulfur compounds is fed to four elevated wet screens for thickening; each wet screen is contained in a vertical rectangular housing approximately 4 ft long by 5 ft wide by 8 ft high. The wet screens will produce a concentrated slurry containing about 40% solids. The 67% slurry of Scheme B is not screened, but flows directly to the conversion tank.

In Schemes A and D, the wet screens are constructed directly above a 12 ft diameter tank designed with a 1,200 ft² steam coil for heating the slurry and converting $MgSO_3 \cdot 6H_2O$ to $MgSO_3 \cdot 3H_2O$. The thickened slurry from the screens flows by gravity to this tank, which is designed for a residence time of 20 min for the thermal conversion. The conversion tank is equipped with a 20-horsepower turbine agitator. After conversion, the slurry is pumped to two parallel 36 in. diameter by 72 in. long solid bowl centrifuges for separation of the solids from the liquor. Two 10-horsepower feed pumps are provided. Each centrifuge is equipped with a 200-horsepower motor. Both the centrate and the screen undersize flow by gravity to a common 5,000-gal receiving tank designed with 50-horsepower pumps for recycle of liquor to the scrubbers and to the magnesia preparation area.

Because the scrubber effluent of Scheme C contains fly ash, but does not contain undissolved magnesium compounds, it is processed differently from Schemes A, B, and D. A bleed stream of slurry from each of the sulfur dioxide absorbers is pumped to a single 105 ft diameter conical-bottom thickener equipped with rake and 5-horsepower drive. The underflow from the thickener, containing about 30% fly ash, is pumped at a rate of about 94 gpm to each of two parallel filters where the fly ash is removed. Two 15-horsepower pumps are provided. The filtrate flows by gravity to a 3,900-gal liquor tank for recycle of solution to the absorbers. Each filter has a surface area of about 60 ft² and is equipped with a 100-horsepower vacuum pump. To provide similar solids disposal as used for the other schemes, the filter cake is slurried with water in a 1,300-gal tank equipped with a 1-horsepower agitator and is pumped as a 15% fly ash slurry to a disposal pond.

The overflow from the thickener flows by gravity to a 24,000-gal reaction-conversion tank equipped with a 1,900 ft² steam coil. This tank is designed for a reaction time of about 20 min. The magnesium sulfite slurry is pumped at a rate of 570 gpm to each of two 36 in. diameter by 72 in. long solid bowl centrifuges operating in parallel. Two 30-horsepower pumps are provided. Each centrifuge is driven by a 200-horsepower motor and is elevated to allow the centrate to flow by gravity to the 3,900-gal liquor tank for recycle to the absorbers.

Sulfite drying-calcining–Representative area layout plan and elevation views of a fluid bed magnesium sulfite drying and calcining area are shown in figures B-15 and B-16. For comparison, a representative area layout plan view of a rotary drying and calcining area is shown in figure B-17. Each view includes the slurry preparation area which has already been described.

The centrifuge cake is fed at a rate of 66,400 lbs/hr to the fluid bed dryer with a 16-in. screw conveyor. The single-stage, fluid bed dryer is constructed of refractory-lined carbon steel and is approximately 18 ft in diameter by 40 ft high. Hot gases are supplied to the dryer from an oil-fired, horizontal, refractory-lined, carbon steel, combustion chamber 10 ft in diameter by 16 ft long. A 250-horsepower blower supplies fluidizing combustion air to the combustion chamber at a rate of approximately 13,200 acfm (ambient temperature). Cleaned dryer exhaust gas at 400° F is recycled to the combustion chamber at 19,500 acfm as a means of controlling the temperature and oxygen content of the feed gas to the dryer. The total gas rate from the dryer is approximately 57,900 acfm at 400° F, and the superficial gas velocity in the dryer is approximately 4.0 ft/sec.

If rotary dryers and calciners are desired for regenerating magnesia, the approximate dimensions of these systems are as shown in table 39.

The offgas from the dryer is partially cleaned in a refractory-lined carbon steel cyclone with a conical bottom; secondary cleaning is accomplished with a fabric dust

Table 39. Approximate dimensions of rotary dryers and calciners.

	Shell diameter	Shell length
Rotary dryer	[illegible] ft	100 ft
Rotary calciner	13 ft 6 in	200 ft

collector. The fabric filter contains approximately 10,500 sq ft of filter area and is 46 ft long by 12½ ft wide by 21 ft high. A 250-horsepower fan is provided for exhausting the cleaned gas to the flue gas plenum for reheat and to the dryer combustion chamber for temperature control.

The solids discharged from the dryer, cyclone, and bag filter are transferred to the $MgSO_3$ silo on a common conveyor-elevator at a rate of approximately 40,000 lbs/hr. The $MgSO_3$ silo is approximately 26 ft in diameter by 43 ft high with a 12 ft conical bottom. If off-site regeneration is required, as in Scheme D, truck loading facilities are provided.

The coke receiving silo is approximately 15 ft in diameter by 21 ft high with an 8 ft conical bottom. A receiving hopper and a conveyor-elevator are included for unloading coke. Variable speed weigh feeders are used for feeding $MgSO_3$ and coke to a common conveyor-elevator which discharges into the fluid bed calciner. This conveyor-elevator also receives recycle from the secondary calciner dust collectors and is designed for an overall feed rate to the calciner of about 39,000 lbs/hr.

The fluid bed calciner is refractory-lined carbon steel and is approximately 16 ft in diameter by 38 ft high. It contains a single calcination bed designed for operation at 1600° F and two air preheat-product cooling stages. Combustion air is fed into the lower cooling stage at a rate of 10,100 acfm at ambient temperature by a 400-horsepower blower. Product MgO is withdrawn from the lower cooling stage at a temperature of 225° F and a rate of 16,900 lbs/hr. The heat for calcination is obtained by direct combustion of fuel oil in the upper stage. The gas flow rate at the discharge of the calciner is 51,900 acfm at 1600° F, and the superficial gas velocity in the calcining bed is approximately 4.0 ft/sec.

An off-site fuel oil storage and feeding system is designed for heating, transferring, and feeding fuel oil to the dryer and calciner. These facilities include insulated storage and holding tanks with heating coils, heat exchangers, and transfer and feed pumps; a 30-day supply of fuel oil is provided.

The offgas from the calciner is partially cleaned in a refractory-lined carbon-steel cyclone with a conical bottom. Prior to secondary cleaning, the gas is cooled to about 700° F in a waste heat boiler and is mixed with the required amount of air for producing sulfuric acid. The combined gas, at a temperature of 400° F and a rate of 44,500 acfm, is fed to a fabric filter for final cleaning before entering the sulfuric acid unit. This filter contains approximately 7,700 sq ft of cloth area and is 34 ft long by 12½ ft wide by 21 ft high. The MgO collected in the bag filter is recycled to the calciner for layout convenience and to insure calcination of the fines.

Slurry preparation–Product MgO from the lower cooling stage discharges onto a conveyor-elevator and is fed to the top of a 30 ft diameter by 31 ft high storage silo with a 12 ft conical bottom. Fresh makeup MgO is received in an 18 ft diameter by 25 ft high silo with a 9 ft conical bottom. A pneumatic conveying system with a 150-horsepower blower is provided for unloading fresh MgO. Each of the silos is equipped with a variable speed feeder beneath the conical bottom. The weigh feeders discharge onto an conveyor-elevator for feeding MgO to the slurry tank. The slurry tank is 24 ft in diameter by 35 ft high and is equipped with a 50-horsepower turbine agitator and two 15-horsepower pumps. The MgO is slurried in a stream of recycle centrate and thickener underflow from the liquor tank and is pumped to the absorption area.

The dimensions of the slurry processing, drying, calcining, and slurry preparation area for a fluid bed installation are approximately 197 ft by 188 ft for a 500-mw power unit. If rotary dryers and calciners are provided, the dimensions for this area would be approximately 320 ft by 188 ft.

Sulfuric acid production and storage–Representative area plan and elevation views of the sulfuric acid production and storage area are shown in figures B-18 and B-19. Since dimensions of the sulfuric acid process equipment depend upon specific design which may vary from vendor to vendor, they are not discussed. However, a 500-mw power unit burning 3.5% S coal requires an area approximately 245 ft long by 188 ft wide for the contact sulfuric acid plant.

The cleaned calciner offgas at a rate of approximately 44,500 acfm at 400° F is dried with a recycle stream of 93% sulfuric acid, and any supplemental water which is required for producing 98% acid is added to the drying tower. The SO_2 in the offgas of the drying tower is converted to SO_3 in a four-stage converter. Prior to entering the converter, the gas is preheated in three vertical indirect gas-to-gas heat exchangers while simultaneously cooling the offgas from the upper and lower converter stages. The converter is designed for supplemental cooling of the offgases of the second and third converter stages below the catalyst beds by indirect heat exchange with air. The heated air is exhausted to the atmosphere. The converter offgas, after passing through the primary heat exchangers, is fed to the absorption tower for direct absorption of SO_3 in 98% H_2SO_4. For an on-site sulfuric acid unit, the tail gas containing SO_2 is recycled to the SO_2 absorbers at a rate of approximately 26,200 acfm at 160° F. For an off-site acid unit, however, separate magnesia tail gas scrubbing, solids separation, and drying facilities are provided. Drip type heat exchangers are incorporated for cooling the product acid and the effluents from both the drying and absorption towers. The net product rate is approximately 386 tons of 98% H_2SO_4/day for a 500-mw, 3.5% S coal-fired installation.

The sulfuric acid unit is designed with three 500,000-gal mild-steel storage tanks with an overall storage capacity equivalent to approximately 1 month's production. These facilities allow for storage of various strengths of acid as may be required by the consumer. The tanks are connected to a common loading station equipped with parallel operating and spare loading pumps.

Equipment delivery and installation—The estimated delivery time required for the various types of equipment may vary considerably depending upon power plant location, method of transportation, and the size of the equipment. Much of the equipment is large and must be field fabricated. Scrubbers, dryers, and calciners, because of their size, are expected to require the longest delivery and erection time. A complete on-site magnesia facility including scrubbing, absorbent regeneration, and sulfuric acid production and storage areas is expected to require about 18-30 months for engineering, procurement, and erection.

INVESTMENT AND OPERATING COST

On the basis of design criteria, assumptions, and equipment selections defined in previous sections, investment and operating cost estimates were prepared for economic evaluation of the four magnesia scrubbing-regeneration schemes. In addition to base case conditions for a new 500-mw power unit burning either coal with 3.5% sulfur content or fuel oil with 2.5% sulfur content, several other combinations of the more important variables were given detailed treatment. Included are variations in sulfur content of fuel, type of fuel (coal or oil), power unit size, and plant status (new vs existing). The estimates are based on a midwestern location and mid-1972 cost levels with the investments corresponding to a Chemical Engineering Cost Index of 136.

Given in table 40 are the individual cases examined. Schemes A, B, and C are evaluated assuming all facilities, including fly ash disposal, at the power plant site, whereas Scheme D covers situations where scrubbing and sulfite drying are performed at the power plant and regeneration and acid manufacture are completed at an off-site central processing plant.

In addition to the magnesia process estimates, updated 1972 limestone-wet scrubbing process costs based on the latest process design, development, and operating data available, are given for comparison. The wet limestone process serves reasonably well as a measurable alternative for SO_2 emission reduction since a directly comparable range of estimates for each process variable can be made. In addition, it is a nonrecovery process not requiring sulfur product marketing. There are other valid alternatives for SO_2 reduction including the use of low sulfur fuels and nuclear power; however, their costs are as widely variable and as difficult to predict as are limestone-wet scrubbing values. Since interest in wet limestone scrubbing is currently high and several pilot plant and full scale installations of the process are being designed, constructed, or operated to test the concept, comparison of magnesia scrubbing-regeneration and wet limestone scrubbing costs should yield a meaningful measure of application potential. For additional evaluation, economic results are given in terms of cost/unit of fuel consumed ($/ton of coal, $/barrel of oil) which can be compared to the premium that must be paid for low sulfur fuel.

The limestone slurry scrubbing process chosen for comparison follows the same basic design premises and criteria as the magnesia processes. For 99% dust removal on coal-fired units, a single-stage venturi scrubber is used. Based on TVA pilot plant test and vendor data, a three-stage mobile bed scrubber is used for 90% SO_2 removal. The particulate scrubber utilizes part of the 10% solids slurry from the SO_2 absorber effluent as scrubbing liquid at a rate of 15 gal/Macf. A liquid to gas ratio of 40 gal/Macf is used in the SO_2 absorber. Makeup limestone is wet ground and added as a 55% solids slurry at a 130% stoichiometric rate. Stack gas reheat to 175° F uses the same methods as outlined for magnesia systems.

Since solids disposal is such a major consideration in throwaway process economics, both variable, low-cost on-site pond disposal and higher off-site disposal at $6/ton of solids are covered. In both cases, closed loop water recirculation is provided. Given in figure 58 is the effect of variation in solids disposal cost on annual limestone-wet scrubbing operating cost. To better reflect the apparent wide range of costs associated with limestone scrubbing between rural and metropolitan locations, along with the high and low solids disposal costs, high and low values of limestone raw material prices are also incorporated. In other words, two sets of limestone wet scrubbing operating costs are prepared, one for systems having low limestone and variable on-site solids disposal costs and another for those units with higher limestone and off-site solids disposal costs. In many cases, the actual costs will probably fall between the two extremes used.

Fixed Investment

The numerous fixed investment estimates are based on extensive vendor contacts, which produced definitive equipment proposals for several of the key process operations. Companies contributing to the depth and accuracy of the equipment costs are listed elsewhere. In addition, authoritative publications on cost estimating are used for the minor items such as tanks and pumps. After process equipment costs are determined, area installation expense is added—the magnesia process costs being estimated from layout and arrangement drawings given in Appendix B, and the limestone costs being determined from study drawings for TVA's Widows Creek scrubbing project. Labor and material breakdowns are prepared by design and cost specialists for the base case estimate and scaled to fit the case deviations.

Table 40. Case combinations for coal- and oil-fired units.

Scheme	Power unit size, mw	Regen-acid unit size equiv., mw	Power plant status	Sulfur content, %
Case combinations–coal-fired units				
A	200	200	New	3.5
	200	200	Existing	3.5
	500	500	Existing	3.5
	500	500	New	2.0
	500 (base case)	500	New	3.5
	500	500	New	5.0
	1,000	1,000	Existing	3.5
	1,000	1,000	New	3.5
B	200	200	New	3.5
	500 (base case)	500	New	3.5
	1,000	1,000	New	3.5
C	200	200	New	3.5
	500 (base case)	500	New	3.5
	1,000	1,000	New	3.5
D	200	200	New	3.5
	5 x 200	1,000	New	3.5
	10 x 200	2,000	New	3.5
	15 x 200	3,000	New	3.5
	500 (base case)	500	New	3.5
	2 x 500	1,000	New	3.5
	4 x 500	2,000	New	3.5
	6 x 500	3,000	New	3.5
	1,000	1,000	New	3.5
	2 x 1,000	2,000	New	3.5
	3 x 1,000	3,000	New	3.5
Case combinations–oil-fired units				
A	200	200	New	1.0
	200	200	New	2.5
	200	200	New	4.0
	200	200	Existing	2.5
	500	500	New	1.0
	500 (base case)	500	New	2.5
	500	500	New	4.0
	500	500	Existing	2.5
	1,000	1,000	New	1.0
	1,000	1,000	New	2.5
	1,000	1,000	New	4.0
	1,000	1,000	Existing	2.5
B	200	200	New	2.5
	500 (base case)	500	New	2.5
	1,000	1,000	New	2.5

Installation costs include piping, ductwork, electrical, instruments, insulation, foundations, structural steel, and painting. In addition, definitive estimates are made on fuel oil storage, product storage, and building needs for motor control, laboratory, locker, and process control space. The investment for on-site disposal ponds for fly ash is not included in the magnesia and limestone estimates as the power plant would be expected to provide this cost regardless of provisions for SO_2 removal. In the limestone estimates, pond cost is provided for the calcium solids when

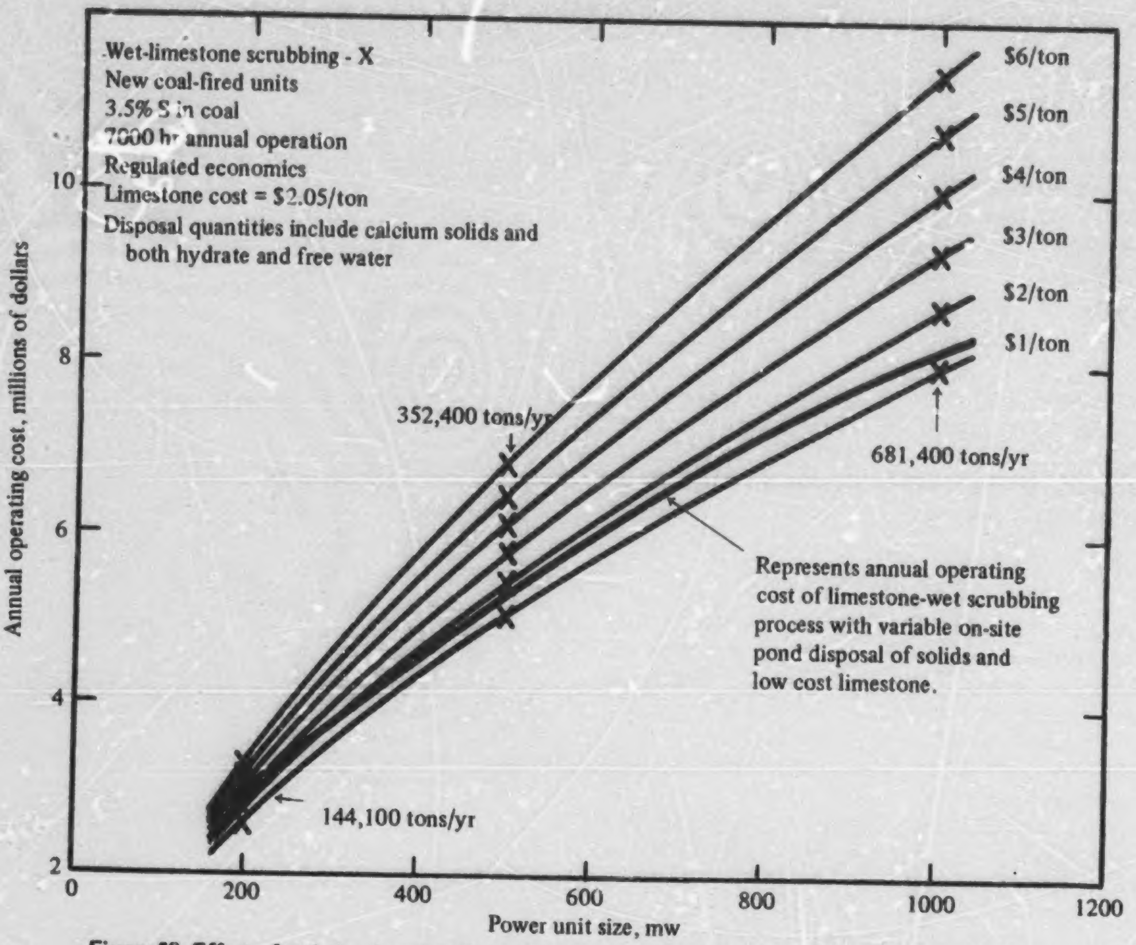

Figure 58. Effect of variation in solids disposal cost on annual limestone-wet scrubbing operating cost.

disposal is on-site. Investment for service areas such as maintenance shops, stores, communication, security, and offices is allocated on the basis of equipment costs and personnel needs of both power plant and stack gas clean-up facilities. Current TVA practice is used as a guide in this effort. For utilities, investment costs are included for distribution facilities, but not for generation facilities. As required in each process area, necessary electrical substations and conduit, steam, process water, fire control water, and compressed air distribution piping are included. The sum of all above items is called direct investment.

To the direct investment is added the indirect costs for the project, which include engineering design and project supervision, construction expense, contractor fees, and contingency. The percentages of direct investment used to estimate these items are shown in table 41.

In keeping with Federal Power Commission accounting practice, allowances are included for start-up and modifications plus interest during construction at 8%/annum. Applied as a percentage of total cost, these allowances are 10% for start-up and 4% for interest. The above percentages are used for the appropriate Scheme A, B, and C cases and for 200-mw, 500-mw, and 1000-mw cases of Scheme D. For the 2000-mw and 3000-mw regeneration-acid plants considered off-site for Scheme D, the percentages listed for new 1000-mw units are applied. Slightly different values are used in the limestone-wet scrubbing estimates, reflecting less complex engineering design and construction.

Working Capital

Working capital requirements are calculated for each case evaluated. As described later, the total of fixed investment and working capital is used in the profitability calculations for determination of return on total investment. For the present study, working capital is defined as the total of 3 weeks of raw materials cost (plus shipping costs between

Table 41. Indirect cost factors.

	Indirect investment cost factors percentage of direct investment					
	Power unit size status					
	200-mw		500-mw		1,000-mw	
	New	Existing	New	Existing	New	Existing
Engineering design and supervision	9	10	7	8	6	7
Construction expense	11	13	9	12	8	9
Contractors fees	6	8	4	6	4	5
Contingency	13	13	12	13	11	12
Total indirects	39	44	32	39	29	33

plants for Scheme D), 7 weeks of direct operating costs (as defined on operating cost sheets in Appendix A), and 7 weeks of overhead cost (as defined on operating cost sheets in Appendix A). No provisions are included for accounts receivable (unpaid billings).

Operating Costs

To present meaningful operating cost estimates, many ground rules and inputs must be defined. Several of the ground rules such as plant life, operating hours/year, process operating conditions, and rates are given in the Study Assumption and Design Criteria section. Others, including raw materials and shipping costs, labor rates, and capital charges are defined here to permit calculation of annual, lifetime, and unit operating costs. All operating cost estimates include the appropriate cost of fly ash and/or calcium solids disposal.

Raw materials–Magnesia process raw materials include magnesium oxide for scrubbing slurry or solution makeup and carbon for reducing magnesium sulfate in the calciner. Both of these materials can be obtained in several forms; however, the need to hold process contamination to a minimum reduces the number of available choices.

Magnesium oxide can be obtained commercially from several companies in one or more forms such as calcined magnesite (dry, 98% MgO), agricultural grade calcined magnesite (dry, 87-92% MgO), magnesium hydroxide (dry, 98% $Mg(OH)_2$), magnesium hydroxide slurry (35-50% $Mg(OH)_2$ in water), and raw, uncalcined magnesite (dry, 45% MgO). Given in table 42 are the f.o.b. costs of these materials both in bulk form and as 100% MgO.

The costs in table 42 do not include shipping which, in most cases, will add considerably to the total charges. Points of material origin include Gabbs, Nevada; St. Louis, Michigan; Ludington, Michigan; Freeport, Texas; and Port St. Joe, Florida. Raw magnesite, the least expensive form of MgO at the point of origin, is found only in Nevada; therefore, considerable shipping cost will be incurred to supply it to customers in the eastern United States. Total cost to the two locations given particular emphasis in this report, Chicago and Philadelphia, would be $90 and $109/ton 100% MgO, respectively.

Table 42. Costs for various magnesium oxide-containing raw materials.[a]

	Cost, $/ton	
Material	Bulk	100% MgO
Calcined magnesite (98% MgO)	92.00	93.88
Agricultural grade calcined magnesite (87% MgO)	48.00	55.17
Magnesium hydroxide (67% MgO)	240.00	358.21
Magnesium hydroxide slurry (34% MgO)	38.00	111.76
Raw, uncalcined magnesite (45% MgO)	22.00	48.89

[a] F.o.b. works, freight not included.

The other four materials can be obtained from most of the listed locations; therefore, their total cost will be influenced less by shipping charges, especially the calcined magnesite (98% MgO).

Of the five materials, only the calcined magnesite (98% MgO) and magnesium hydroxide (both dry and slurry form) are low in impurities. Until experience is gained from long-term operation, it has been assumed that the impurity level of raw, uncalcined magnesite and agricultural grade calcined magnesite would require excessive recycle or decontamination cost. Dolomitic limestone should also be considered in the same category.

Taking into consideration both economic and process requirements, the calcined magnesite containing approximately 98% MgO should be considered as the prime magnesia source. This material is produced by calcination of magnesium hydroxide from sea water and natural brines.

A typical chemical composition is as follows:

Magnesium oxide, %	97-99.0
Calcium oxide, %	0.55-1.00
Silca (SiO_2), %	0.20-0.40
Iron oxide (Fe_2O_3), %	0.05-0.25
Aluminum oxide (Al_2O_3), %	0.04-0.20

The material is a fine, crystalline powder with a bulk density of about 20-30 lbs/cu ft.

For purposes of calculating process operating cost, the magnesium oxide cost to a Chicago customer is considered to be $102.40/ton delivered and to a Philadelphia customer, $128.40/ton delivered.

The most suitable form of carbon for addition to the calciner is probably high grade coke. Other reductants such as coal, excess fuel oil, natural gas, or hydrogen might tend to promote H_2S formation or increase ash contamination in the system. Although some of these fuels, coal in particular, are less expensive than coke, considerable additional calcination research is needed before they can be considered.

Based on contract high purity coke prices to TVA during 1971, the delivered cost of coke is predicted to be $23.50/ton. Petroleum coke cost would be less ($5-$10/ton); however, its impurity level may be too high. Since coke cost is a minor part of the process cost, using a high purity coke will not add appreciably to total operating requirements.

In addition to the primary raw materials, makeup catalyst (usually vanadium pentoxide) is required for the sulfuric acid plant. This can be in either extruded, pelletized, or spherical shapes, depending on the original charge provided by the plant designer. Cost is expected to be about $1.51/liter.

An additional raw material required for Scheme B is manganese dioxide. In the variation researched by Grillo-Werke AG, pyrolusite, a natural ore found in Africa and containing 87% plus MnO_2, is used as an activator for the MgO-SO_2 reaction. A few U. S. companies import this material and process it in relatively small quantities. For such quantities as required by MgO-MnO_2 scrubbing of stack gas, indications are that ground pyrolusite can be delivered to midwestern power plants for $90/ton.

In defining the operating costs of the limestone-wet scrubbing process, the cost of limestone has major significance. Data from a recent report by M. W. Kellogg (53) indicate the costs of limestone delivered to various U. S. power plants range from $1.95 to $13.20/ton; at least half of the power plants in the eastern U. S. could be supplied at $4/ton or less; and all but three could obtain limestone for less than $6/ton. In separate studies made in the TVA area, prices were found to range from $2.05 to $4.05/ton delivered. Since the use of limestone-wet scrubbing as a process comparison should reflect the possible variance in limestone costs, operating cost projections will cover both high and low cost raw material. The high cost will be $6/ton and the low cost $2.05/ton. Shown in figure 59 is the effect of limestone cost on the total annual operating cost of the limestone-wet scrubbing process.

Shipping cost–central processing concept–To fully define the economics of the central processing concept (multi-location scrubbing and drying plus single location for regeneration and acid manufacture), the shipping cost for transferring magnesium sulfite and magnesium oxide between locations must be included as part of the total process operating cost. Furthermore, for display purposes, it is necessary to assign the shipping costs to one or the other operating cost summaries; that is, to the operating cost for the scrubbing-drying operation or to that of the regeneration-acid manufacturing operation. The assignment is arbitrary; however, for purposes of this, the magnesium sulfite shipping cost is included as part of the raw material cost for the regeneration-acid manufacturing operation and the magnesium oxide shipping cost is included as part of the raw material cost for the scrubbing operation.

Combinations of scrubbing plant distances from the central plant are almost limitless; therefore, to simplify evaluation of shipping distance, all scrubbing-drying locations are assumed to be equidistant from the central regeneration plant. Distances of 5, 25, 50, 75, 100, and 150 miles from the central point are examined.

For magnesium sulfite shipping, 1972 rail rates are not available; however, the magnesium sulfate rates shown in table 43 can be used (covered hopper cars in the Philadelphia and Chicago areas, not less than 80,000 lbs).

Magnesium oxide shipping costs, as shown in table 44, apply to Philadelphia and Chicago for rail shipment in covered hopper cars, not less than 120,000 lbs.

Estimated trucking costs for both magnesium sulfite and magnesium oxide for the Philadelphia and Chicago areas are shown in table 45, assuming 40,000-lb loads and mixed loading, that is, some trucks hauling both ways and others

Table 43. Rail shipping costs for magnesium sulfate.

Miles distance	Rate in cents per hundred pounds	Rate in cents[b] per ton-mile
5[a]	17	68
25	35	28
50	36	14
75	41	11
100	46	9
150	52	7

[a] Inside switching limits.
[b] Early 1972 rates.

Table 44. Rail shipping costs for magnesium oxide.

Miles distance	Rate in cents per hundred pounds	Rate in cents[b] per ton-mile
5[a]	17	68
25	24	19
50	25	10
75	27	7
100	31	6
150	38	5

[a] Inside switching limits.
[b] Early 1972 rates.

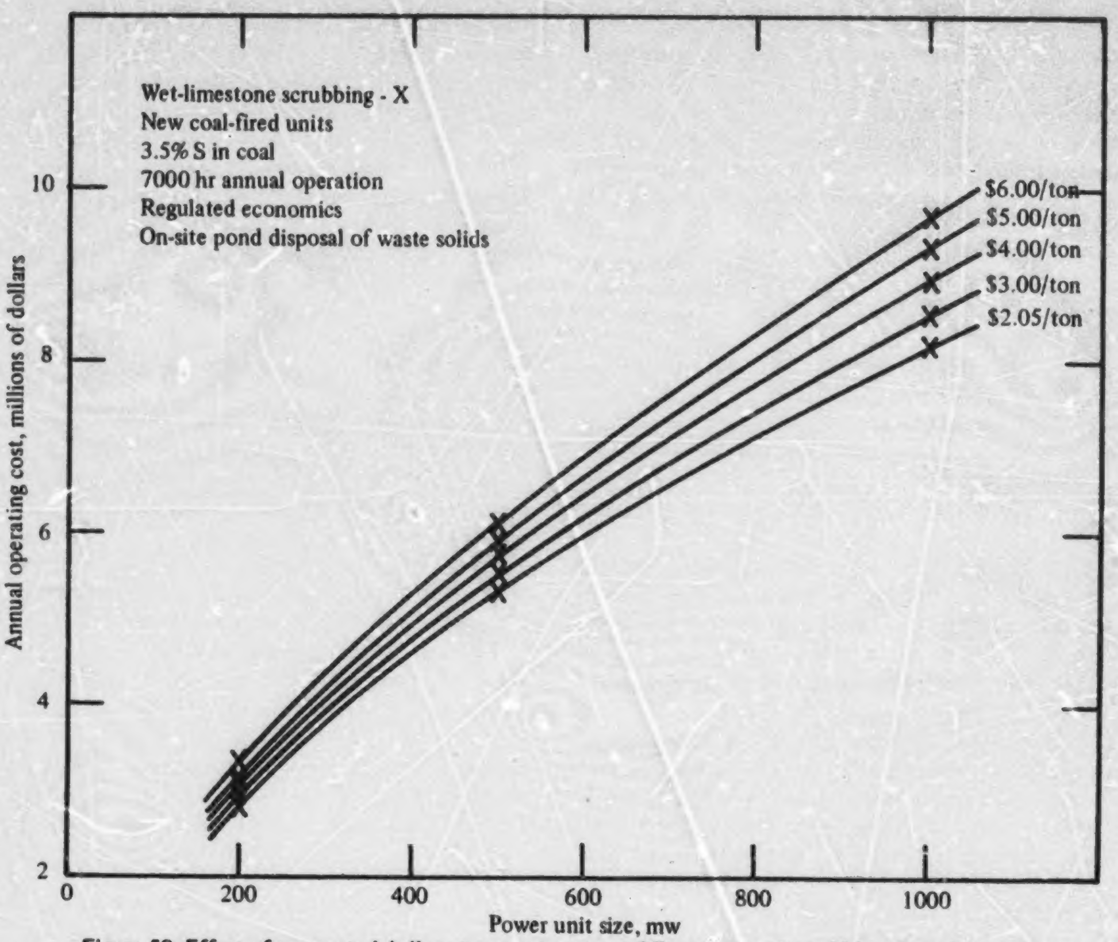

Figure 59. Effect of raw materials limestone cost on annual limestone-wet scrubbing operating cost.

Table 45. Trucking costs for magnesium sulfate or magnesium oxide.

Miles distance	Cost in cents per hundred pounds	Cost in cents[b] per ton-mile
5	12[a]	48
25	12[a]	10
50	12[a]	5
75	15	4
100	18	4
150	25	3

[a] Minimum cost.
[b] Early 1972 rates.

one way (more magnesium sulfite than magnesium oxide must be shipped).

Shipping by truck appears to be less expensive than by rail and offers a great deal more flexibility. For the cost estimates in this study, truck shipping is assumed at the rates shown.

It should be mentioned that barge shipping rates can be even lower than for trucking when large quantities are involved. Barging is, of course, limited to those sites on navigable waterways, but in many cases power units are located on such rivers and lakes. Barging, however, requires additional handling and storage facilities for the transfer of large quantities of material with minimum delay, and because barging rates are not readily predictable (barge lines negotiate each individual contract and are quite flexible as contrasted to fairly rigid truck and rail costs), they are not considered in this evaluation.

Labor–Labor costs used are based on current TVA power plant and chemical plant operator rates and for most of the cost estimates are not escalated over the life of the project. To permit some measure of the effect of escalating labor costs, a comparison is presented in the section on

Profitability and Economic Potential using different rates of escalation. With the present uncertainty of future labor costs and productivity increases, it is not possible to accurately predict the effect of labor rates on the total cost. The base operating labor rate of $6/hr includes fringe benefits and supervisory expense. The higher labor rates of $10/hr used for laboratory work also includes benefits, supplies, and supervisory expense.

Utilities—The costs of utilities to the process depend on quantity, source, and accounting practice. The values used are fully allocated costs, as if purchased from an independent source with full capital recovery provided for. As quantities increase, the unit cost of utilities is decreased to show some economy of scale. For existing power plants, it is recognized that no excess steam, water, or electricity would be available and that new investment would be required by the independent source; the new investment is not included in that shown for the process, but a higher cost is charged to permit more rapid capital recovery than for new plants. For new plants, the utility costs are the same as would be charged to power plant operation by the plant accountant since provision could be made to furnish the necessary utilities in the original design and installation. For those cases where a heat credit is taken for export steam to the power unit system, the value of the credit is based only on equivalent fuel cost.

Maintenance—Maintenance costs chargeable to the magnesia processes are considered "best estimates." Indications are that some scaling and corrosion-erosion will be encountered in the scrubber system, at least to a greater extent than for processes not using slurry scrubbing. Solids handling and calcining operations usually are maintenance prone. Sulfuric acid plant maintenance is more easily predicted since such plants have been in operation for years. For purposes of this study, table 46 shows estimated overall maintenance costs as a percent of magnesia process investment.

Maintenance charges used in the limestone-wet scrubbing estimates range from 6 to 9% of investment depending on unit size. Experience from pilot plants and actual installations seem to support a higher maintenance charge as compared to the magnesia system because of slurry acidity (5.5-7.0 pH vs 7.0-8.5 pH for magnesia), the greatest tendency to form scale deposits, and the apparently higher erosive characteristics of the calcium sulfite crystal.

Capital charges—Estimation of operating cost is complicated by the fact, as discussed in the ammonia scrubbing conceptual design study (84), that projects for sulfur and nitrogen oxides control in power plants may be financed on different bases—the regulated power industry basis, the nonregulated chemical industry practice, or a combination of the two. This has a major effect on capital charge items such as depreciation and taxes. Because of this important factor, two sets (one regulated, one nonregulated) of operating cost estimates are made for each of the magnesia Scheme A, B, and C case combinations of plant size, power unit status, fuel type, and sulfur content of fuel. For Scheme D a single set of estimates is prepared; however, the operating cost of the scrubbing-drying operation is assumed to be under power industry economics (regulated) and the regeneration-acid plant operation under chemical industry economics. This so-called cooperative economics probably best describes the type of combined venture for the central process concept. It is the most likely financing method for a magnesia system.

For the power industry (regulated utility economics), the usual practice is followed of including in the capital charges a regulated return on investment and the state and Federal income taxes. A breakdown of the capital charges is given in table 47. The depreciation rate is straight line, based on the remaining life of the power plant after the pollution control process is installed, and is a percentage of initial fixed investment. Interim replacements and property insurance are also based on original fixed investment. However, because most regulatory commissions base the annual premissible return on investment on the remaining depreciation base (that portion of the original investment yet to be recovered or "written off"), a portion of the annual capital charge to be applied to the operating cost declines uniformly over the life of the investment.

Annual return on equity, interest on outstanding debt, and income taxes are established in the same manner. The cost of money to the power industry is assumed to be 8% interest on borrowed funds and 12% return on equity money to attract investors. Assuming a capital structure of 50% debt and 50% equity, the overall cost of money under

Table 46. Estimated overall maintenance costs.

	Total system maintenance-percentages of investment				
	200-mw	500-mw	1,000-mw	2,000-mw	3,000-mw
Scrubbing	6	6	6	–	–
Drying-calcining	9	7	5	5	4
Sulfuric acid	9	5	3	3	3
Storage	3	3	3	3	2
Composite	7	6	5	4	3

Table 47. Annual capital charges for power industry financing (new power unit with 30-yr life).

	As percentage of original investment
Depreciation (based on 30-yr life for a new power unit)	3.33
Interim replacements (equipment having less than 30 yr life)	0.67
Insurance	0.50
Total rate applied to original investment	**4.50**
	As percentage of outstanding depreciation base[a]
Cost of capital (capital structure assumed to be 50% debt and 50% equity)	
Bonds at 8% interest	4.00
Equity at 12% return to stockholder	6.00
Taxes	
Federal (50% of gross return or same as return on equity)	6.00
State (national average for states in relation to Federal rates)	4.80
Total rate applied to depreciation base	**20.80[b]**

[a] Original investment yet to be recovered or "written off."

[b] Applied on an average basis, the total annual percentage of original fixed investment would be 4.5% + ½ (20.80%) = 14.90%.

regulated economics comes to 10%. Federal income taxes are assumed to be 50% of gross income and state tax is assumed to be 80% of the national tax; the resulting figure is higher than for nonregulated industry, but is about the nationwide average for power companies.

All operating cost estimates for the nonrecovery, limestone wet scrubbing process are calculated on a regulated economic basis.

For chemical industry financing (nonregulated economics), the only capital charges applied are depreciation, local taxes, and insurance. Hence the estimates are not directly comparable with those for power company financing because the latter include return on investment and income tax. Moreover, the depreciation rate for the nonregulated economics basis (10%), which is commonly used in the industry, is much higher than for regulated economics (3.33% for 30 years).

Using different bases for the estimates is confusing, but is necessary as these are the approaches that may be actually used in practice. The encountered difficulty is that the regulated and nonregulated bases can not be directly compared. The fairly well defined return on investment for the power company makes a low rate of depreciation acceptable, and return on investment can be logically included in production cost because it is a fixed charge usually passed on to the power customer. For the chemical company, however, a relatively high rate of depreciation is needed because of the risk factor, and return on investment is quite variable because it can not always be passed on to the customer as a cost item.

Results

A summary of fixed investment for 29 Scheme A, B, and C cases plus comparative estimates for nonrecovery limestone-wet scrubbing with on-site solids disposal pond is presented in table 48. The magnesia process estimates are shown by functional area in tables A-1 to A-23 in Appendix A. A similar analysis of limestone scrubbing investment is given in table A-32 of Appendix A.

The results for Scheme A, the basic slurry process, range from $5,148,000 ($25.7/kw) for a new 200-mw oil-fired unit to $36,634,000 ($36.6/kw) for an existing 1000-mw coal-fired unit. Comparable investments for limestone-wet scrubbing are $4,981,000 ($24.9/kw) and $30,041,000 ($30.0/kw). Investments for Scheme B, the MgO-MnO_2 variation, are barely higher for comparable cases (less than 3% higher), primarily because of greater material handling costs due to inerts and MnO_2 plus more dilute calciner offgas to the sulfuric acid unit (13% SO_2 vs 16% for Scheme A). Comparable Scheme C results are lower than either slurry process, with savings coming from single stage scrubbing (vs two stages for other coal-fired schemes) and reduced process throughput due to less effective SO_2 removal.

Given in table 49 is an equipment, labor, and material cost breakdown for the direct investment of the process areas in the Scheme A base case (new 500-mw coal-fired unit burning coal containing 3.5% sulfur). Table 50 shows the same type breakdown for the limestone-wet scrubbing process with on-site solids disposal. The values in these tables can be used to scale costs to other sizes. Note, however, that building and service facilities are not included in these breakdowns.

The summarized results of table 48 are further considered in figures 60 to 67 which describe the effect of unit size, unit status, fuel type and sulfur content of fuel on total fixed investment.

During the preparation of the magnesia cost estimates, some doubt was expressed by a process developer as to the need for several provisions included in the proposed conceptual designs. Items questioned in particular are:

1. The use of rubber-lined piping in the scrubber circulation and slurry processing systems instead of carbon steel as used in the Boston Edison demonstration.

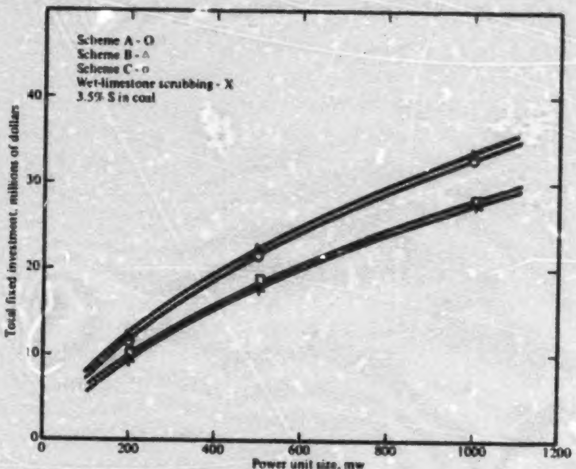

Figure 60. Effect of power unit size on magnesia process investment: new coal-fired units.

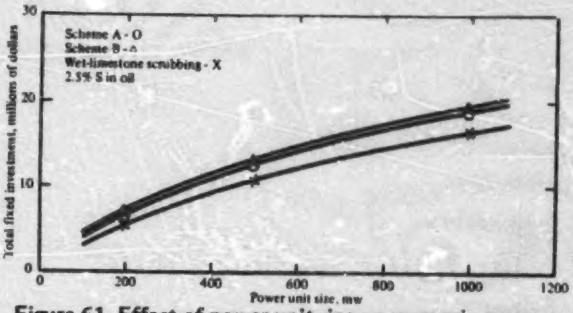

Figure 61. Effect of power unit size on magnesia process investment: new oil-fired units.

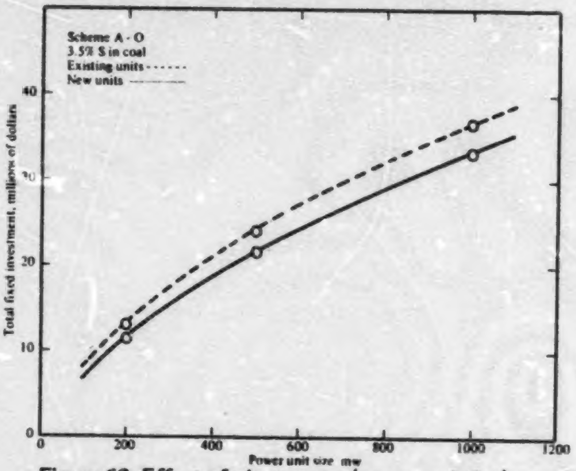

Figure 62. Effect of plant status (new vs existing) on investment for magnesia Scheme A: coal-fired power units.

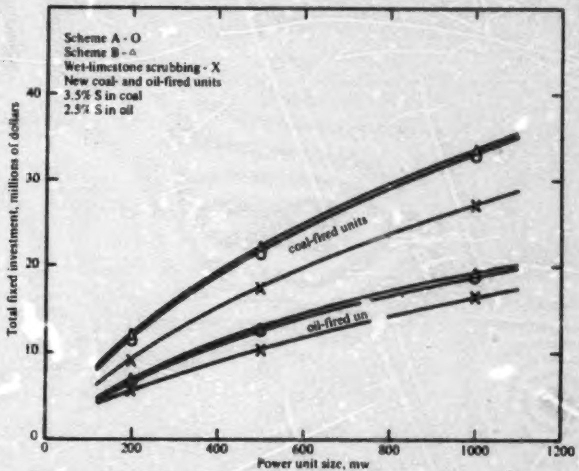

Figure 63. Effect of power unit fuel type on investment.

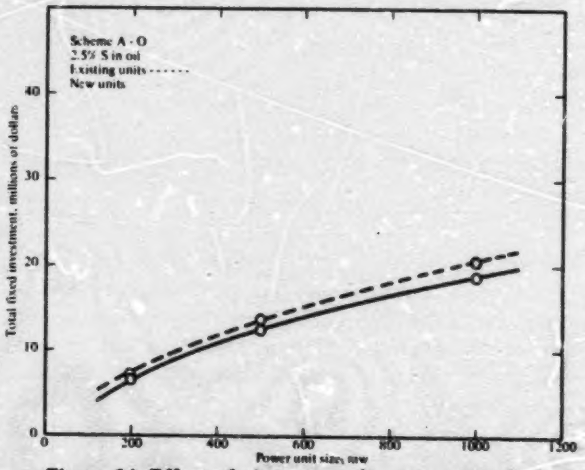

Figure 64. Effect of plant status (new vs existing) on investment for magnesia Scheme A: oil-fired power units.

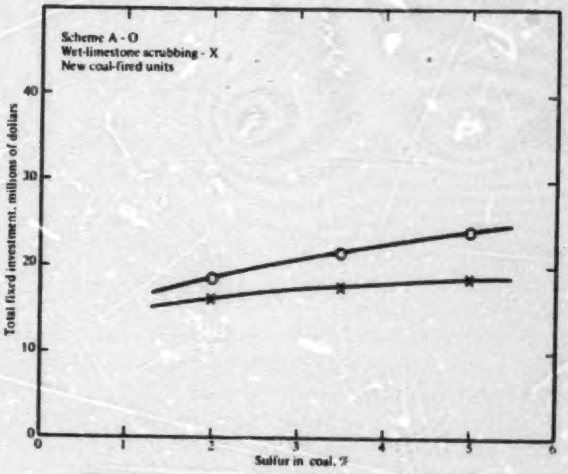

Figure 65. Effect of sulfur content of coal on investment: 500-mw units.

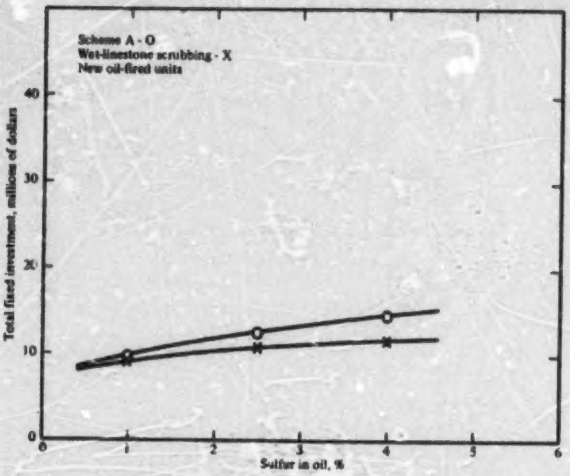

Figure 66. Effect of sulfur content of oil on investment: 500-mw units.

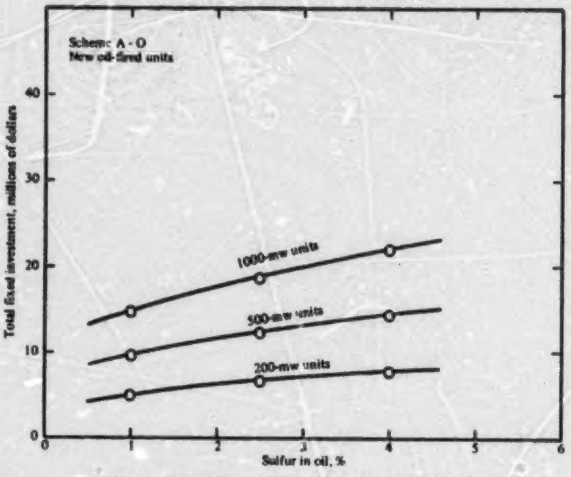

Figure 67. Effect of plant size and sulfur content of oil on investment.

2. Use of a stainless steel conversion tank and centrifuge, and rubber-lined tanks, pumps, and agitators in the slurry processing and MgO slurry preparation areas rather than carbon steel units.

3. The inclusion of special facilities for purge treatment of contaminents instead of allowing them to accumulate to a level such that losses would offset the inputs.

4. The extra provisions for sulfite hexahydrate conversion to sulfite trihydrate crystals which may be more difficult to dewater.

It can be seen in table 51 that those design differences add up to a significant potential investment savings ($909,600 for the base case, coal-fired Scheme A, a 4.2% savings). The first three, of course, are included in the conceptual design as safe measures in the face of uncertainty in process performance and the fourth provision offers considerable operating cost savings (lower fuel requirements in dryer) if operationally feasible. Since the need for these provisions can only be determined from actual demonstration operation over a period of time, this study provides for their inclusion in the process design and cost evaluation. As data is received from the Boston Edison project, adjustments can be made accordingly to magnesia process economics.

Table 48. Total fixed investment requirements—magnesia scrubbing and limestone-wet scrubbing processes.[a]

Case	Magnesia		Limestone-wet scrubbing	
	$	$/kw	$	$/kw
Coal fired				
Scheme A				
200-mw N 3.5% S	11,685,000	58.4	9,192,000	46.0
200-mw E 3.5% S	13,083,000	65.4	10,304,000	51.5
500-mw E 3.5% S	24,646,000	49.3	19,958,000	39.9
500-mw N 2.0% S	18,788,000	37.6	16,172,000	32.3
500-mw N 3.5% S	21,732,000	43.5	17,622,000	35.2
500-mw N 5.0% S	24,275,000	48.5	18,928,000	37.8
1,000-mw E 3.5% S	36,634,000	36.6	30,041,000	30.0
1,000-mw N 3.5% S	33,118,000	33.1	27,413,000	27.4
Scheme B				
200-mw N 3.5% S	11,990,000	60.0	9,192,000	46.0
500-mw N 3.5% S	22,237,000	44.5	17,622,000	35.2
1,000-mw N 3.5% S	33,838,000	33.8	27,413,000	27.4
Scheme C				
200-mw N 3.5% S	9,923,000	49.6	9,192,000	46.0
500-mw N 3.5% S	18,111,000	36.2	17,622,000	35.2
1,000-mw N 3.5% S	27,540,000	27.5	27,413,000	27.4
Oil fired				
Scheme A				
200-mw N 1.0% S	5,148,000	25.7	4,981,000	24.9
200-mw N 2.5% S	6,690,000	33.4	5,700,000	28.5
200-mw N 4.0% S	7,903,000	39.5	6,288,000	31.4
200-mw E 2.5% S	7,426,000	37.1	6,608,000	33.0
500-mw N 1.0% S	9,888,000	19.8	9,491,000	19.0
500-mw N 2.5% S	12,439,000	24.9	10,679,000	21.4
500-mw N 4.0% S	14,568,000	29.1	11,696,000	23.4
500-mw E 2.5% S	13,920,000	27.8	12,392,000	24.8
1,000-mw N 1.0% S	14,957,000	14.9	14,766,000	14.8
1,000-mw N 2.5% S	18,888,000	18.8	16,629,000	16.6
1,000-mw N 4.0% S	22,046,000	22.0	18,202,000	18.2
1,000-mw E 2.5% S	20,740,000	20.7	18,556,000	18.6
Scheme B				
200-mw N 2.5% S	6,806,000	34.0	5,700,000	28.5
500-mw N 2.5% S	12,561,000	25.1	10,679,000	21.4
1,000-mw N 2.5% S	19,126,000	19.1	16,629,000	16.6

[a] N = New plants
E = Existing plants
S = sulfur

Table 49. Process equipment and installation analysis-direct cost for Scheme A[a] (thousands of dollars).

	Particulate scrubbing	SO_2 scrubbing	Slurry processing	Drying	Calcining	MgO slurrying	New H_2SO_4 production	H_2SO_4 storage	Optional bypass duct	Fuel oil storage	Total
Equipment											
Material	828	997	424[b]	490[b]	665[b]	115	925	163	–	122	4,729
Labor	240	256	75	176	215	27	Inc.	Inc.	–	22	1,011
Piping & insulation											
Material	327	236	52	2	2	15	410	–	–	Inc.	1,044
Labor	177	101	20	3	3	4	Inc.	–	–	Inc.	308
Ductwork, dampers, & insulation											
Material	752	878	–	20	44	–	741	–	454	Inc.	2,889
Labor	Inc.	Inc.	–	Inc.	Inc.	–	Inc.	–	Inc.	Inc.	Inc.
Concrete-foundations											
Material	105	115	30	38	46	10	188	18	–	21	571
Labor	Inc.	Inc.	Inc.	Inc.	Inc.	Inc.	Inc.	Inc.	–	Inc.	Inc.
Structural											
Material	135	145	26	8	14	3	99	3	–	2	435
Labor	180	190	34	11	18	4	Inc.	4	–	Inc.	441
Electrical											
Material	216	340	73	43	39	32	207	14	–	10	974
Labor	Inc.	Inc.	Inc.	Inc.	Inc.	Inc.	Inc.	Inc.	–	Inc.	Inc.
Instruments				(Additional instruments)							
Material	111	135	29	11	32	39	185	Inc.	–	1	543
Labor	57	75	10	4	11	13	Inc.	Inc.	–	Inc.	170
Paint											
Material	66	60	12	4	5	2	66	1	–	Inc.	216
Labor	Inc.	Inc.	Inc.	Inc.	Inc.	Inc.	Inc.	Inc.	–	Inc.	Inc.
Subtotal Direct costs	3,194	3,528	785	810	1,094	264	2,821	203	454	178	13,331

[a] New plant, coal-fired, 500-mw, 3.5% S in coal, 1,040,000 scfm stack gas, 378 tpd H_2SO_4.
[b] Includes most instrumentations.

Inc. = included.

Another potential route to reduction of magnesia process investment requirements is the use of an existing sulfuric acid plant. In most such cases, new gas purification facilities, estimated at 40% of the cost of a new acid unit, would need to be installed. The existing heat exchangers, converter, absorber and storage tanks could be used, thereby saving considerable new investment as shown in table 52. It is difficult, however, to predict how such savings would affect overall process economics (operating cost, potential profitability). Most accepted accounting procedures would still require all investment utilized, regardless of new or existing status, to be depreciated and to earn a return. Since the age and condition of the existing acid unit would influence the capital charges applied, each case would have to be evaluated with care. It should be pointed out that other chargeable operating costs such as labor, utilities, and maintenance would not be reduced by using an existing acid plant.

The fixed investment requirements for Scheme D, the central processing concept, are summarized in table 53 and shown in detail in tables A-24 to A-31 in Appendix A. As can be seen in figure 68, Scheme D requires about 6% more investment than Scheme A, which represents the same process technique, but with all facilities at the same site. For combinations of 200-mw, 500-mw, and 1000-mw scrubbing facilities coupled with various-size central regeneration-acid plants, figure 69 describes the effect of total system size in megawatts on total fixed investment. Given in table 54 are the process unit sizes in megawatts and the equivalent sulfuric acid capacity when burning coal with 3.5% sulfur content.

Although a single Scheme D system is more costly than a single Scheme A facility, desirable investment economy can

Table 50. Process equipment and installation analysis[a] direct cost for limestone-wet scrubbing process (thousands of dollars)

	Limestone handling, storage & grinding	Scrubbing system including fans & reheat	Optional bypass duct	Solids disposal & pond water recycle	Total
Equipment					
Material	293	2,364	–	57	2,714
Labor	75	306	–	38	419
Piping & insulation					
Material	53	1,062	–	182	1,297
Labor	31	402	–	113	546
Ductwork, dampers, & insulation					
Material	–	812	250	–	1,062
Labor	–	598	150	–	748
Concrete-foundations					
Material	24	51	–	80	155
Labor	56	123	–	65	244
Excavation, site prep.	150	125	–	1,127	1,402
Structural					
Material	17	395	–	–	412
Labor	21	428	–	–	449
Electrical					
Material	80	310	–	36	426
Labor	81	217	–	43	341
Instruments					
Material	12	222	–	12	246
Labor	4	186	–	8	198
Paint					
Material	6	35	–	2	43
Labor	9	65	–	3	77
Land	30	10	–	565	605
Subtotal–direct cost	942	7,711	400	2,331	11,384

[a] New unit, coal-fired, 500-mw, 3.5% S in coal, 1,040,000 scfm stack gas, indirect steam reheat to 175° F, on-site solids disposal, closed loop water recycle.

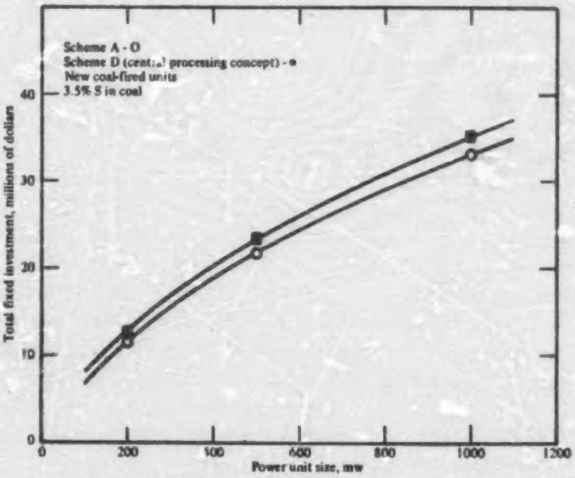

Figure 68. Effect of power unit size on total fixed investment for Scheme D vs Scheme A.

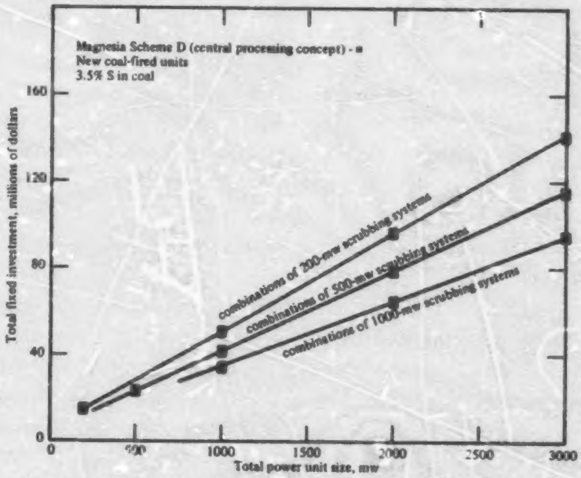

Figure 69. Effect of total system size on fixed investment: central regeneration concept.

Table 51. Possible reduction in investment[a] requirements for magnesia Scheme A—special design provisions.

	Investment savings $
Equipment material—change from stainless steel to carbon steel in slurry processing and MgO slurry areas	93,500
Piping and insulation—change to a carbon steel piping system for particulate scrubbing, SO_2 scrubbing, slurry processing and MgO slurry areas	269,500
Eliminate purge treatment in slurry processing area	160,000
Eliminate slurry processing between screens and centrifuges	81,500
Subtotal direct cost savings	604,500
Engineering design and supervision	42,300
Construction expense	54,400
Contractor fees	24,200
Contingency	72,500
Subtotal fixed capital investment savings	797,900
Allowance for startup and modifications	79,800
Interest during construction (8%/annum rate)	31,900
Total fixed capital investment savings	909,600

[a] New plant, coal fired, 500-mw, 3.5% S in coal, 1,040,000 scfm stack gas, 378 tpd H_2SO_4.

Table 52. Comparison of investment requirements for a magnesia system including a new sulfuric acid unit with a system using an existing acid unit.

Case	Magnesia investment including new acid unit		Magnesia investment with existing acid unit	
	$	$/kw	$	$/kw
Coal fired				
Scheme A				
200-mw N 3.5% S	11,685,000	58.4	9,963,000	49.8
500-mw N 3.5% S	21,732,000	43.5	18,686,000	37.4
1,000-mw N 3.5% S	33,118,000	33.1	28,424,000	28.4
Oil fired				
Scheme A				
200-mw N 2.5% S	6,690,000	33.4	5,673,000	28.4
500-mw N 2.5% S	12,439,000	24.9	10,648,000	21.3
1,000-mw N 2.5% S	18,888,000	18.8	16,084,000	16.1

Existing acid plant investment reduction calculated using 60% of acid plant investment cost, 100% of acid storage cost, and 20% of service facilities cost. Appropriate indirect costs were added.

be achieved when multiboiler combinations are considered as shown in table 55.

Presented in table 56 is a summary of annual and unit operating costs (7,000 hrs/yr) for magnesia Schemes A, B, and C under regulated (power industry) economics. Comparison with both high and low cost limestone scrubbing (1972 cost basis) is also provided. Except for the 200-mw cases, the magnesia operating costs fall between the high and low limestone cost values.

Magnesia process annual and unit operating costs under nonregulated economics are shown in table 57. As would be expected, the nonregulated values are lower than the regulated cost results since profit and income taxes are not included; however, comparison of the two sets of values has little meaning since their derivation purposes are different.

Lifetime operating costs for power unit operating profiles given earlier are summarized in table 58 for selected magnesia process cases. As apparent, operating costs over a 30-year power unit life are quite significant. Keep in mind that these particular values do not include provision for labor and materials inflation which most assuredly will increase the expected costs.

Details backing the summarized results are given in tables A-33 to A-80 in Appendix A. For Schemes A, B, and C, 46 operating cost tables are included, 23 for regulated and 23 for nonregulated examples. In addition, two limestone-wet scrubbing operating cost estimates for a new 500-mw coal-fired unit with 3.5% sulfur in the fuel are included. One estimate covers a low cost limestone system; the other covers the high cost example.

Note that the annual capital charges (percent of fixed investment) shown in the regulated base tables are average values since it is not practical to present the variable declining balance portion of the charge (see table 47) used in regulated cost analysis. The average capital charge multiplied by the number of years of operation will give the same actual outlay of dollars as the declining balance calculation; however, the present worth of the two methods will be different (discounted to 1972 dollars). There is, of

Table 53. Total fixed investment requirements Scheme D—central process concept.

Scrubbing-drying		Regeneration-acid manufacture		Total system	
Unit size, mw	$	Unit size, mw	$	Unit size, mw	$
200	7,671,000	200	5,017,000	200	12,688,000
5 x 200	38,355,000	1,000	12,354,000	1,000	50,709,000
10 x 200	76,710,000	2,000	19,534,000	2,000	96,244,000
15 x 200	115,065,000	3,000	26,096,000	3,000	141,161,000
500	14,844,000	500	8,294,000	500	23,138,000
2 x 500	29,688,000	1,000	12,354,000	1,000	42,042,000
4 x 500	59,376,000	2,000	19,534,000	2,000	78,910,000
6 x 500	89,064,000	3,000	26,096,000	3,000	115,160,000
1,000	22,673,000	1,000	12,354,000	1,000	35,027,000
2 x 1,000	45,346,000	2,000	19,534,000	2,000	64,880,000
3 x 1,000	68,019,000	3,000	26,096,000	3,000	94,115,000

Table 54. Scheme D unit combinations: rated acid production capacity.[a]

Scrubbing-drying size		Regeneration-acid production	Tons/day,
Number	mw	mw	100% H_2SO_4
1	200	200	136
5	200	1,000	680
10	200	2,000	1,360
15	200	3,000	2,040
1	500	500	331
2	500	1,000	662
4	500	2,000	1,324
6	500	3,000	1,986
1	1,000	1,000	640
2	2,000	2,000	1,280
3	3,000	3,000	1,920

[a] Based on burning coal with 3.5% S, 92% evolved as SO_2, "90% recovered," 3% material handling losses; and 8,000 hr annual operation for regeneration-acid manufacturing unit.

course, another method (sinking fund depreciation plus interest, or capital recovery factor) of presenting a single annual percentage of initial investment which will give the same present worth of the lifetime capital charges as the declining balance calculation approach, but the actual dollar outlay will be different. Of the two procedures, the average capital charge method has been chosen for annual operating cost tables because it can incorporate straight line depreciation, thus permitting simpler adjustment of the percentage of initial investment for power units with various remaining lives.

Using the tables of Appendix A for 7,000 hrs/yr operation, the effects of several variables on magnesia process operating costs are shown graphically in figures 70 to 82.

The annual and unit operating costs for Scheme D case combinations are shown in table 59 for operation at each site. The totals in table 59 are described graphically in figures 83 and 84. The values given represent a cooperative venture utilizing regulated economics for 7,000 hrs/yr operation at the power plant site, and nonregulated economics with 8,000 hrs/yr operation at the acid plant

Table 55. Comparison of Scheme A total investment with Scheme D total investment for similar capacity installations.

Single site Scheme A system		Separate site, Scheme D system		
Mw	Total investment $	Scrubbing-drying, mw	Regeneration-acid mfr., mw	Total investment $
One 200	11,685,000	200	200	12,688,000
Five 200	58,425,000	5 x 200	1,000	50,709,000
Ten 200	116,850,000	10 x 200	2,000	96,244,000
Fifteen 200	175,275,000	15 x 200	3,000	141,161,000
One 500	21,732,000	500	500	23,138,000
Two 500	43,464,000	2 x 500	1,000	42,042,000
Four 500	86,928,000	4 x 500	2,000	78,910,000
Six 500	130,392,000	6 x 500	3,000	115,160,000
One 1,000	33,118,000	1,000	1,000	35,027,000
Two 1,000	66,236,000	2 x 1,000	2,000	64,880,000
Three 1,000	99,354,000	3 x 1,000	3,000	94,115,000

Table 56. Average operating costs for magnesia scrubbing processes compared to limestone-wet scrubbing process under regulated economics.[a]

	Magnesia processes			Limestone-wet scrubbing process			
				Low limestone cost,[b] on-site solids disposal		High limestone cost,[c] off-site solids disposal	
	Average annual cost	Unit operating cost		Average annual cost	Unit operating cost	Average annual cost	Unit operating cost
Coal fired	$	$/ton coal	$/ton acid	$	$/ton coal	$	$/ton coal
Scheme A							
200-mw E 3.5% S	4,297,200	7.75	92.22	3,214,700	5.80	4,002,600	7.22
200-mw N 3.5% S	3,870,700	7.21	85.64	2,869,200	5.35	3,633,400	6.77
500-mw E 3.5% S	7,762,500	5.79	68.76	5,927,900	4.42	8,253,700	6.15
500-mw N 2.0% S	5,913,900	4.51	93.72	4,801,000	3.66	6,347,600	4.84
500-mw N 3.5% S	7,048,900	5.37	63.85	5,376,300	4.10	7,621,500	5.81
500-mw N 5.0% S	8,066,600	6.15	51.12	5,894,000	4.49	8,861,700	6.75
1,000-mw E 3.5% S	11,494,700	4.38	52.04	8,981,900	3.42	13,879,900	5.08
1,000-mw N 3.5% S	10,635,400	4.19	49.82	8,230,900	3.24	12,883,100	5.08
Scheme B							
200-mw N 3.5% S	3,939,600	7.34	87.16	2,869,200	5.35	3,633,400	6.77
500-mw N 3.5% S	7,161,300	5.46	64.87	5,376,300	4.10	7,575,900	5.77
1,000-mw N 3.5% S	10,803,800	4.26	50.60	8,230,900	3.24	12,883,100	5.08
Scheme C							
200-mw N 3.5% S	3,389,400	6.32	87.58	2,869,200	5.35	3,633,400	6.77
500-mw N 3.5% S	6,094,800	4.64	64.36	5,376,300	4.10	7,575,900	5.77
1,000-mw N 3.5% S	9,193,100	3.62	50.24	8,230,900	3.24	12,883,100	5.08
Oil fired	$	$/bbl oil	$/ton acid	$	$/bbl oil	$	$/bbl oil
Scheme A							
200-mw E 2.5% S	2,557,300	1.20	102.70	2,111,700	1.03	2,329,800	1.10
200-mw N 1.0% S	1,725,300	0.84	178.97	1,596,700	0.78	1,638,300	0.80
200-mw N 2.5% S	2,305,600	1.12	95.67	1,836,700	0.89	2,046,900	0.99
200-mw N 4.0% S	2,751,900	1.34	71.48	2,044,500	0.99	2,441,400	1.19
500-mw E 2.5% S	4,548,800	0.88	75.56	3,755,100	0.73	4,556,000	0.89
500-mw N 1.0% S	3,214,200	0.64	136.20	2,898,800	0.58	3,163,100	0.63
500-mw N 2.5% S	4,159,800	0.83	70.63	3,343,600	0.66	4,112,500	0.82
500-mw N 4.0% S	4,973,500	0.99	52.80	3,747,300	0.74	5,046,700	1.00
1,000-mw E 2.5% S	6,822,000	0.68	57.91	5,694,500	0.57	7,483,800	0.74
1,000-mw N 1.0% S	4,217,200	0.50	105.87	4,443,400	0.46	5,079,200	0.52
1,000-mw N 2.5% S	6,317,100	0.65	55.46	5,160,400	0.53	6,848,000	0.70
1,000-mw N 4.0% S	7,566,300	0.78	41.53	5,824,300	0.60	8,607,200	0.88
Scheme B							
200-mw N 2.5% S	2,274,400	1.11	94.37	1,836,700	0.89	2,046,900	0.99
500-mw N 2.5% S	4,053,100	0.81	68.81	3,343,600	0.66	4,122,500	0.82
1,000-mw N 2.5% S	6,126,200	0.63	53.79	5,160,400	0.53	6,848,000	0.70

[a] 7,000 hr operation/yr.

[b] Limestone at $2.05/ton and variable disposal cost for fly ash and calcium solids–ranges from $2.85/ton to $1.33/ton.

[c] Limestone at $6/ton and $6/ton disposal cost for fly ash and calcium solids.

site. The costs include shipping expense in the Chicago area for transporting the magnesium sulfite and recycle magnesium oxide up to 50 miles by truck. The results are based on passing the costs incurred in the scrubbing-drying operation to the raw material costs of the regeneration-acid manufacturing operation. This procedure is used only for the individual Scheme D cost sheets shown in Appendix A under tables A-81 to A-94. In the Profitability and Economic Potential section of this report, a different procedure will be examined.

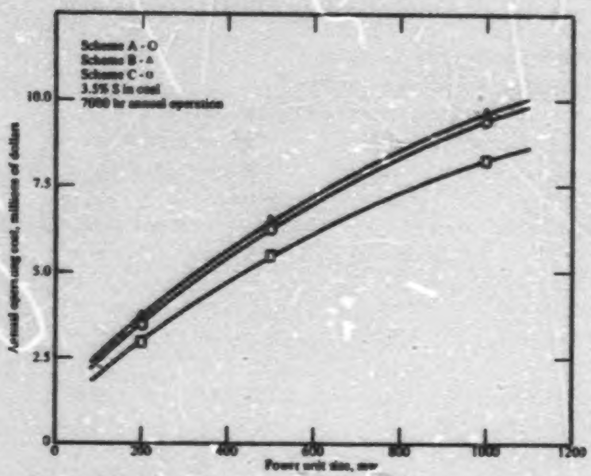

Figure 70. Effect of power unit size on annual operating cost: new coal-fired units under nonregulated economics.

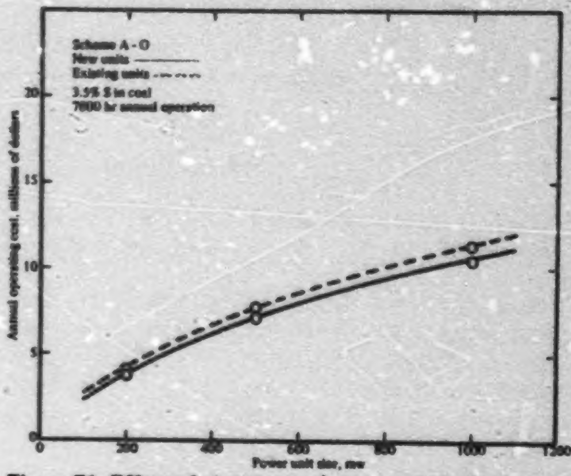

Figure 71. Effect of plant status (new vs existing) on annual operating cost: coal-fired units under regulated economics.

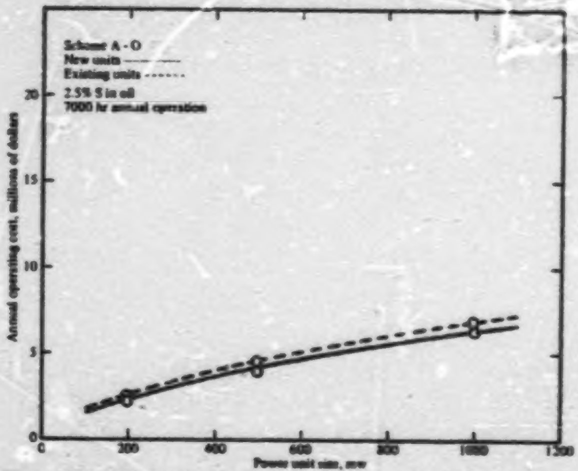

Figure 72. Effect of plant status (new vs existing) on annual operating cost: oil-fired units under regulated economics.

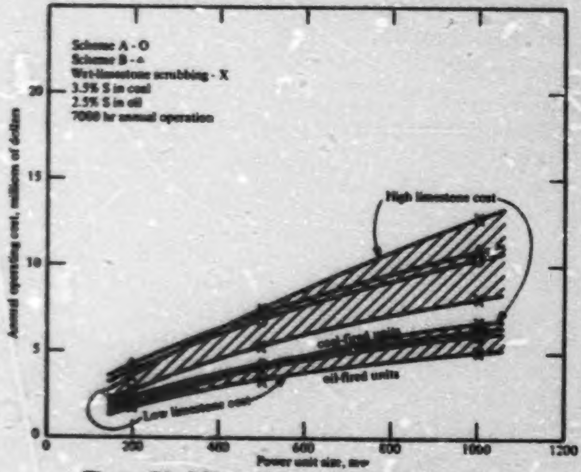

Figure 73. Effect of power unit size on annual operating costs: regulated economics.

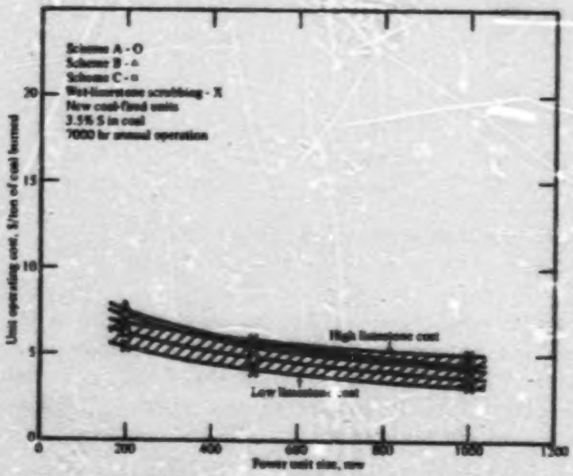

Figure 74. Effect of power unit size on unit operating cost: coal-fired units under regulated economics.

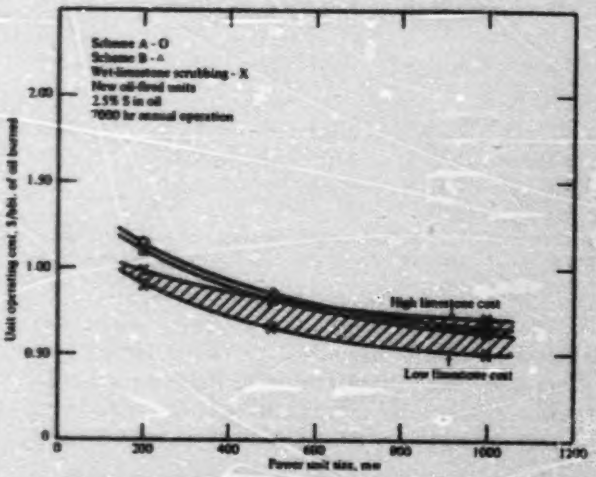

Figure 75. Effect of power unit size on unit operating cost: oil-fired units under regulated economics.

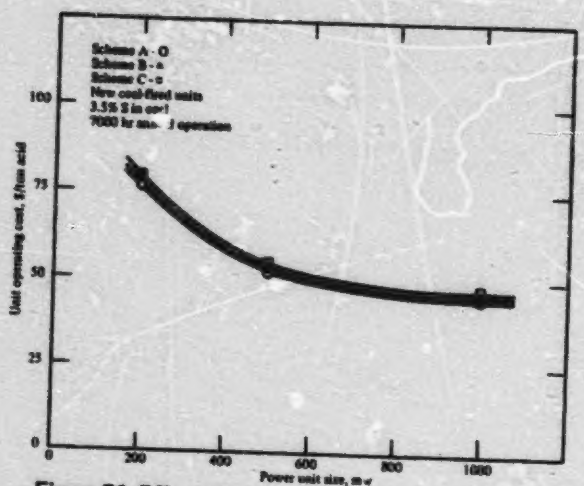

Figure 76. Effect of power unit size on unit operating cost of acid: coal-fired units under nonregulated economics.

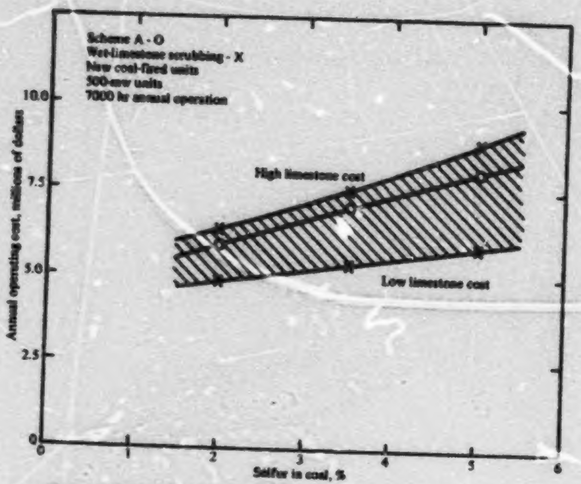

Figure 77. Effect of sulfur content of coal on annual operating cost under regulated economics.

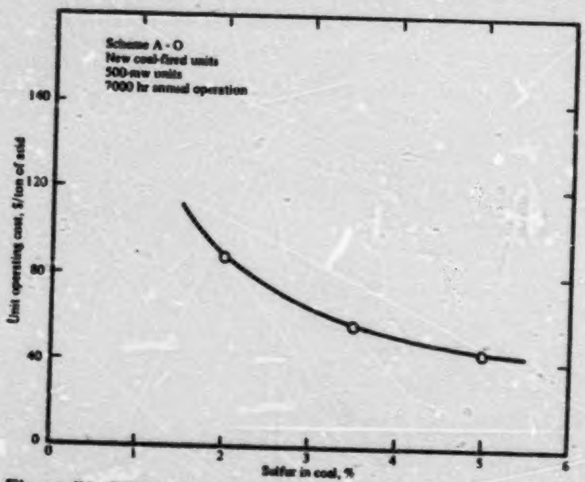

Figure 78. Effect of sulfur content of coal on unit operating cost of acid under nonregulated economics

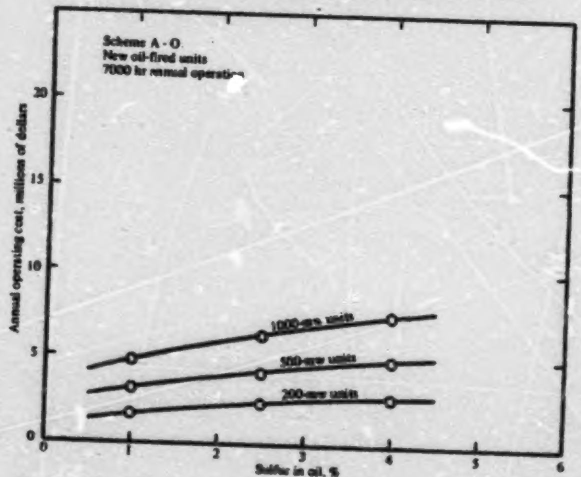

Figure 79. Effect of sulfur content of oil on total annual operating costs under regulated economics.

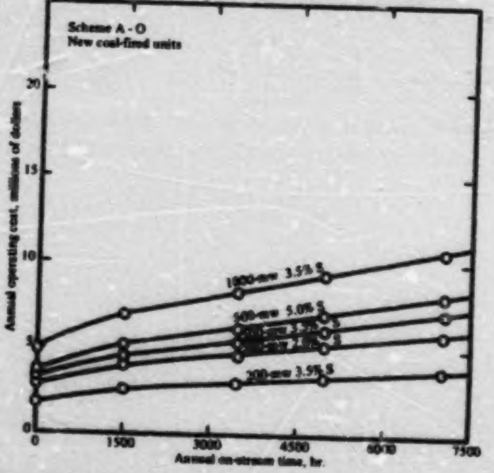

Figure 80. Effect of annual operating time on annual operating cost under regulated economics.

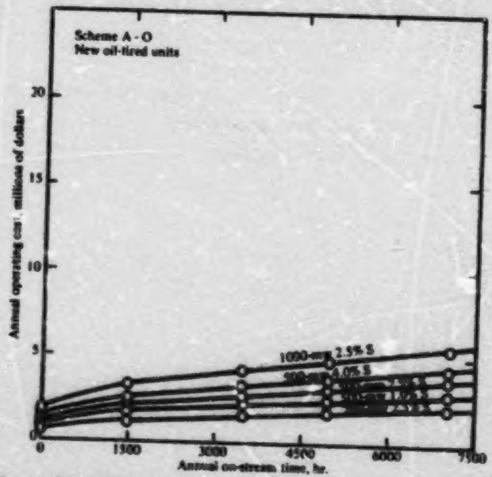

Figure 81. Effect of annual operating time on annual operating cost under nonregulated economics.

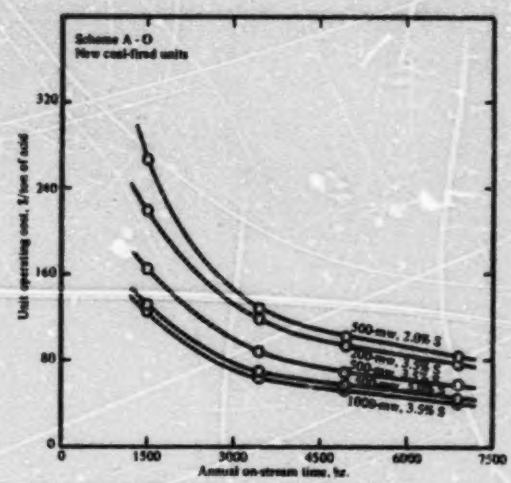

Figure 82. Effect of annual operating time on unit operating cost of acid under nonregulated economics.

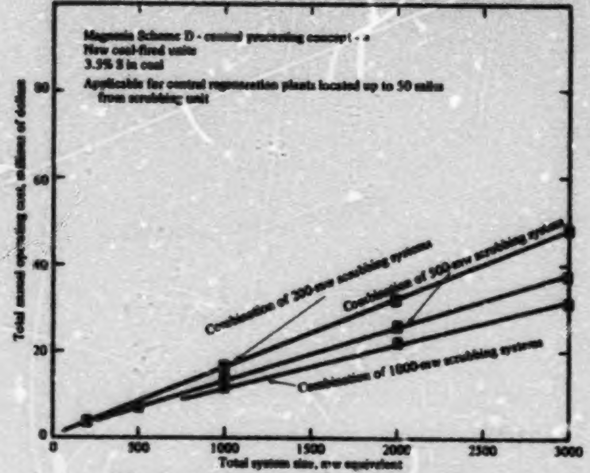

Figure 83. Central regeneration system: effect of total system size on annual operating costs under cooperative economics.

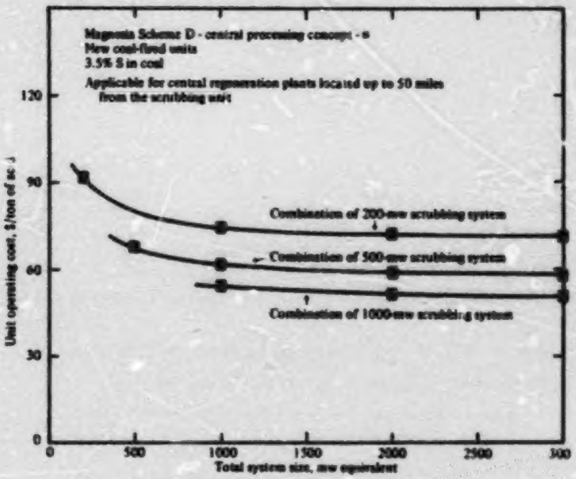

Figure 84. Central regeneration system: effect of total system size on unit operating cost under cooperative economics.

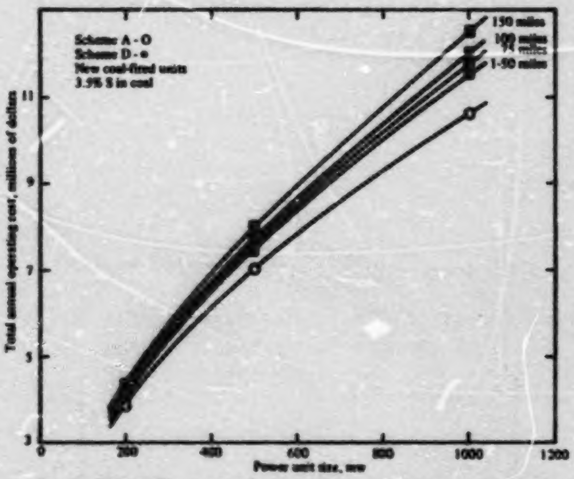

Figure 85. Effect of shipping distance on total annual operating cost for Scheme D under cooperative economics.

Table 57. Annual operating costs for magnesia scrubbing processes under nonregulated economics.[a]

	Magnesia processes		
	Annual cost	Unit operating cost	
Coal fired	$	$/ton coal	$/ton acid
Scheme A			
200-mw E 3.5% S	3,746,400	6.76	80.40
200-mw N 3.5% S	3,468,400	6.46	76.73
500-mw E 3.5% S	6,879,300	5.13	60.93
500-mw N 2.0% S	5,276,300	4.02	83.62
500-mw N 3.5% S	6,306,400	4.81	57.12
500-mw N 5.0% S	7,232,500	5.51	45.83
1,000-mw E 3.5% S	10,185,100	3.88	46.11
1,000-mw N 3.5% S	9,508,800	3.75	44.54
Scheme B			
200-mw N 3.5% S	3,523,400	6.57	78.06
500-mw N 3.5% S	6,404,400	4.88	58.01
1,000-mw N 3.5% S	9,657,200	3.81	45.23
Scheme C			
200-mw N 3.5% S	3,044,600	5.67	78.67
500-mw N 3.5% S	5,469,100	4.17	57.75
1,000-mw N 3.5% S	8,245,100	3.25	45.06
	Annual cost		
Oil fired	$	$/bbl oil	$/ton acid
Scheme A			
200-mw E 2.5% S	2,241,000	1.05	90.00
200-mw N 1.0% S	1,547,200	0.75	160.50
200-mw N 2.5% S	2,072,500	1.01	86.00
200-mw N 4.0% S	2,476,100	1.20	64.31
500-mw E 2.5% S	4,044,800	0.79	67.19
500-mw N 1.0% S	2,875,200	0.57	121.83
500-mw N 2.5% S	3,730,800	0.74	63.34
500-mw N 4.0% S	4,469,000	0.89	47.44
1,000-mw E 2.5% S	6,070,600	0.60	51.53
1,000-mw N 1.0% S	4,306,000	0.44	94.64
1,000-mw N 2.5% S	5,666,600	0.58	49.75
1,000-mw N 4.0% S	6,802,800	0.70	37.34
Scheme B			
200-mw N 2.5% S	2,039,700	0.99	84.64
500-mw N 2.5% S	3,625,100	0.72	61.55
1,000-mw N 2.5% S	5,477,000	0.56	48.09

[a] 7,000 hr operation/yr.

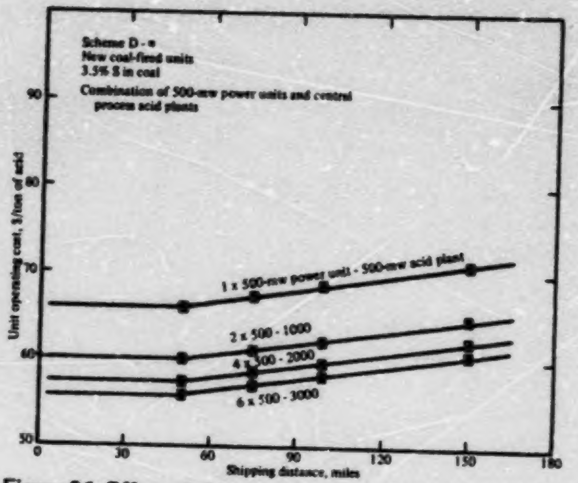

Figure 86. Effect of shipping distance on unit cost of acid for combinations of Scheme D scrubbing and regeneration plants under cooperative economics.

As can be derived from tables 56 and 59, a single unit Scheme D system has a higher operating cost than comparable single-site Scheme A facilities; however, when multiple units are considered, the potential economy is improved as indicated in table 60. In addition, the results indicate that the smaller the power units making up the system, the greater the potential economy of central processing over single-site processing.

The effect of shipping distance on total annual operating cost for single 200-mw, 500-mw, and 1000-mw Scheme D systems is shown in figure 85. In addition, figure 86 displays the effect of shipping distance on unit cost of acid for combinations of 500-mw scrubbing-drying units coupled with a central regeneration-acid production unit.

Table 58. Lifetime operating costs[a] for magnesia scrubbing processes (new plants).

	Regulated economics			Nonregulated economics		
Coal fired 3.5% S in coal	Total operating cost $	Unit operating cost $/ton coal	Unit operating cost $/ton acid	Total operating cost $	Unit operating cost $/ton coal	Unit operating cost $/ton acid
Scheme A						
200-mw	96,608,400	9.88	117.31	60,559,000	6.19	73.54
500-mw	175,486,300	7.34	87.24	108,584,000	4.54	53.98
1,000-mw	263,737,400	5.71	67.81	161,926,500	3.51	41.63
Scheme B						
200-mw	98,516,700	10.08	119.63	61,556,000	6.30	74.75
500-mw	178,601.100	7.47	88.79	110,195,000	4.61	54.78
1,000-mw	268,289,700	5.80	68.98	164,349,000	3.56	42.25
Scheme C						
200-mw	84,056,700	8.60	119.14	53,380,500	5.46	75.66
500-mw	150,473,300	6.29	87.26	94,586,500	3.95	54.85
1,000-mw	225,932,400	4.89	67.79	141,061,000	3.05	42.32
Limestone-wet scrubbing process–low limestone cost, on-site solids disposal						
200-mw	72,705,900	7.43	–	–	–	–
500-mw	136,225,900	5.70	–	–	–	–
1,000-mw	208,272,000	4.51	–	–	–	–
Limestone-wet scrubbing process–high limestone cost, off-site solids disposal						
200-mw	82,657,700	8.46	–	–	–	–
500-mw	170,642,600	7.14	–	–	–	–
1,000-mw	283,172,800	6.13	–	–	–	–
Oil fired 2.5% S in oil	Total operating cost $	$/bbl oil	$/ton acid	Total operating cost $	$/bbl oil	$/ton acid
Scheme A						
200-mw	57,300,100	1.53	130.52	36,597,500	0.98	83.37
500-mw	103,052,300	1.13	96.09	64,675,000	0.71	60.30
1,000-mw	155,385,400	0.88	74.92	97,163,500	0.55	46.85
Scheme B						
200-mw	56,979,700	1.52	129.79	35,966,000	0.96	81.93
500-mw	101,363,200	1.11	94.51	62,705,500	0.68	58.47
1,000-mw	152,398,000	0.86	73.48	93,614,500	0.53	45.14
Limestone-wet scrubbing process–low limestone cost, on-site solids disposal						
200-mw	40,426,700	1.08	–	–	–	–
500-mw	73,531,800	0.81	–	–	–	–
1,000-mw	112,526,700	0.64	–	–	–	–
Limestone-wet scrubbing process–high limestone cost, off-site solids disposal						
200-mw	47,671,000	1.27	–	–	–	–
500-mw	94,255,700	1.03	–	–	–	–
1,000-mw	154,350,700	0.87	–	–	–	–

[a] 30 yr life; 7,000 hr–10 yr, 5,000 hr–5 yr, 3,500 hr–5 yr, 1,500 hr–10 yr.

Table 59. Total operating costs for Scheme D.[a]

Scrubbing-drying operation (regulated economics)			Regeneration-acid manufacture (nonregulated economics)			Total, cooperative economics	
Mw	$	$/ton $MgSO_3$	Mw	$	$/ton acid	$	$/ton acid
200	2,498,900	44.43	200	1,650,600	36.52	4,149,500	91.80
5 x 200	12,494,500	44.43	1,000	4,407,500	19.50	16,902,000	74.78
10 x 200	24,989,000	44.43	2,000	7,718,300	17.08	32,707,300	72.36
15 x 200	37,483,500	44.43	3,000	10,897,100	16.07	48,380,600	71.36
500	4,665,300	34.93	500	2,838,100	25.71	7,503,400	67.97
2 x 500	9,330,600	34.93	1,000	4,286,300	19.41	13,616,900	61.67
4 x 500	18,661,200	34.93	2,000	7,460,500	16.89	26,121,700	59.15
6 x 500	27,991,800	34.93	3,000	10,169,400	15.35	38,161,200	57.61
1,000	7,409,300	28.69	1,000	4,181,900	19.59	11,591,200	54.29
2 x 1,000	14,818,600	28.69	2,000	7,252,300	16.98	22,070,900	51.69
3 x 1,000	22,227,900	28.69	3,000	9,856,900	15.39	32,084,800	50.09

[a] Cooperative venture economics; new coal-fired units; 3.5% S in coal; 7,000 hr/yr scrubbing-drying; 8,000 hr/yr regeneration acid manufacture.

Table 60. Total annual operating cost: combinations of power unit systems in Scheme D.

Single site systems (regulated economics)		Separate site systems (cooperative economics)		
Mw	$	Scrubbing-drying mw	Regeneration-acid manufacture mw	$
One 200	3,870,700	200	200	4,149,500
Five 200	19,353,500	5 x 200	1,000	16,902,000
Ten 200	38,707,000	10 x 200	2,000	32,707 300
Fifteen 200	58,060,500	15 x 200	3,000	48,380,600
One 500	7,048,900	500	500	7,503,400
Two 500	14,097,800	2 x 500	1,000	13,616,900
Four 500	28,195,600	4 x 500	2,000	26,121,700
Six 500	42,293,400	6 x 500	3,000	38,161,200
One 1,000	10,635,400	1,000	1,000	11,591,200
Two 1,000	21,270,800	2 x 1,000	2,000	22,070,900
Three 1,000	31,906,200	3 x 1,000	3 000	32,084,800

[a] New coal-fired units, 3.5% S in coal.

PROFITABILITY AND ECONOMIC POTENTIAL

For nonrecovery stack gas desulfurization processes such as limestone-wet scrubbing, no sale of product is involved; therefore, identification of investment and operating costs provides sufficient measure for comparison with some alternate methods of pollution control. However, for recovery processes such as magnesia scrubbing-regeneration, which yield a salable product, a more extensive evaluation (83) is required including the estimation of product sales credit or revenue, the preparation of cash flow projections over the years of power unit life, and the use of recognized standards for measuring profitability of capital expenditures.

Estimation of sales revenue can be particularly difficult since many factors including plant location, plant operating flexibility, plant capacity, sales volume, and marketing policy affect competition with new and existing sources of sulfur based products. In this report, a cursory market investigation is presented to establish a basis for making this rather hazardous forecast; however, it is recognized that a more complete, thorough study of the sulfur, sulfuric acid, and related markets is needed for accurate assessment of product value.

In the market analysis given herein, consideration is focused on defining historical sulfuric acid capacity, production, consumption, and market growth, spotlighting grades of acid and end-uses, plus locating acid plants and power plants for the purpose of predicting the best end-use markets for the acid, market location, and pricing policy.

Using assumed sales values along with the appropriate investment and operating cost data, year-by-year computer-calculated cash flows are prepared under regulated economics (declining depreciation base) for each of the 29 magnesia process cases cited earlier and compared directly with the limestone-wet scrubbing process which has no sales revenue. In addition, appropriate nonregulated cash flows are also projected and profitability determined for the magnesia processes. The evaluation of the central processing concept under cooperative economics (scrubbing-drying, regulated; regeneration-acid manufacture, nonregulated) is more complex than the methods used for either regulated or nonregulated economics alone; therefore, a modified set of assumptions will be used for Scheme D.

Marketing

The primary product of magnesia scrubbing processes, sulfuric acid, is the most widely manufactured chemical in the world. In 1970, approximately 91,000,000 metric tons, 100% H_2SO_4 equivalent, were produced; 69,743,000 tons in the noncommunist countries and 21,249,000 tons in the communist nations (9). This represented an increase of 5% over 1969 figures and an 8% increase over 1968. For North America, the U. S. and Canada, 27,735,000 metric tons of acid were produced, an increase of only 2.5% over the previous year. The U. S. alone manufactured over 91% of this quantity and the U. S. production of 25,260,000 metric tons represents an increase of 64% since 1960.

Consumption of sulfuric acid in the U. S. in 1970 was approximately 3.8% greater than in 1969, which is a slightly larger increase than for production (10). Approximately 28,675,000 metric tons were consumed, 13% more than manufactured during the year. Most of the difference came from inventories as very little acid is imported, only about 90-150,000 metric tons/yr.

From U. S. Department of Commerce data (93), a summary of sulfuric acid production in short tons for each month of 1972 is shown in table 61. The total represents an increase of approximately 5.5% over 1971 production.

Current manufacturing capacity for sulfuric acid approaches 40 million short tons of acid/year with more

Table 61. Summary of U.S. sulfuric acid production–1972 (93).

Month	Short tons
January	2,439,946
February	2,446,800
March	2,678,765
April	2,645,560
May	2,712,606
June	2,521,804
July	2,487,157
August	2,659,375
September	2,494,789
October	2,659,767
November	2,627,615
December	2,671,892
Total for year	31,046,076

than half of capacity committed to captive use. Available data (14) indicates that in 1966, only about 13 million tons were marketed out of approximately 28 million tons produced. As shown in figure 87, states having the most capacity for acid manufacture include Florida (Tampa region), Louisiana, Texas, New Jersey, and Illinois. A state-by-state breakdown of capacity as of 1970 is shown in table 62. Of the 200 or so plants in the U. S., 170 utilize the contact process and the remainder the chamber process. Chamber acid output is estimated to be about one-half million tons/year or less than 2% of the total production.

Individual acid plant sizes have been on the increase for several years, with some units of 3,000 tons/day capacity in operation (13). The larger plants are usually part of large fertilizer complexes using acid captively. Most plants use sulfur as the raw material, approximately 75% in 1966; however, the number of plants processing pyrites, smelter gases, acid sludge, and hydrogen sulfide are increasing as more stringent pollution control laws come into play. At this time, only demonstration systems for catalytic oxidation (EPA-Monsanto-Illinois Power) and magnesia scrubbing (EPA-Chemico-Basic-Boston Edison) are producing sulfuric acid from power plant offgas. More acid is sure to come from this source.

Based on data from industry sources the major end-uses of sulfuric acid in the U. S. are given in table 63 with the quantities being shown for 1970. As can be seen, the predominant consumer of sulfuric acid is chemical fertilizer. In 1970, North American consumption of sulfuric acid for fertilizer manufacture represented approximately 54% of the total quantity of sulfuric acid consumed (9) compared to approximately 43% during 1969 (8).

Table 62. Sulfuric acid plant capacity—short tons per day (14).

Alabama	1,610	Mississippi	1,067
Arizona	2,627	Missouri	3,303
Arkansas	737	New Jersey	6,913
California	6,774	New Mexico	446
Colorado	1,483	New York	583
Delaware	1,050	North Carolina	3,480
Florida	23,661	Ohio	3,180
Georgia	1,369	Oklahoma	630
Idaho	3,470	Pennsylvania	2,177
Illinois	6,944	Rhode Island	50
Indiana	2,066	South Carolina	324
Iowa	1,877	Tennessee	4,421
Kansas	747	Texas	9,855
Kentucky	550	Utah	2,133
Louisiana	12,600	Virginia	1,983
Maine	223	Washington	333
Maryland	2,260	West Virginia	470
Massachusetts	330	Wisconsin	67
Michigan	1,301	Wyoming	360
		Grand total	114,294

Table 63. Sulfuric acid end-use pattern—1970.

	Thousand short tons (100% basis)
Fertilizer	
Phosphoric acid products	13,750
Normal superphosphate	1,240
Cellulosics	
Rayon	520
Cellophane	170
Pulp and paper	600
Petroleum alkylation	2,400
Iron and steel pickling	800
Nonferrous metallurgy	
Uranium ore processing	300
Copper leaching	350
Chemicals	
Ammonium sulfate—coke oven	500
synthetic	480
chemical byproduct	190
Chlorine drying	150
Alum	600
Caprolactam	260
Dyes and intermediates	370
Detergents, synthetic	400
Chrome chemicals	100
HCl	150
HF	880
TiO_2	1,440
Alcohols	1,800
Other chemicals	380
Industrial water treatment	200
Storage batteries	140
Other processing	470
Total	**28,640**

Although most of the sulfuric acid consumed in fertilizer manufacture is concentrated, high quality material, wet process phosphoric acid produced by reacting sulfuric acid with phosphate rock can be made with off-grade acid. For the other end-uses of sulfuric acid, high purity and high concentration are almost mandatory.

As is apparent from table 63, sulfuric acid has a wide variety of uses, some of which are based on excellent physcial properties, but most on cost. Sulfuric acid is very often preferred over other mineral acids, chemicals or different process technology because it is the least expensive alternative. For example, in phosphate rock acidulations and phosphoric acid manufacture, its major end-use, it is the lowest cost acidulant available. There was a period in the late 1960's when this was under challenge as sulfur prices rose to higher levels; however, the sulfur shortage was

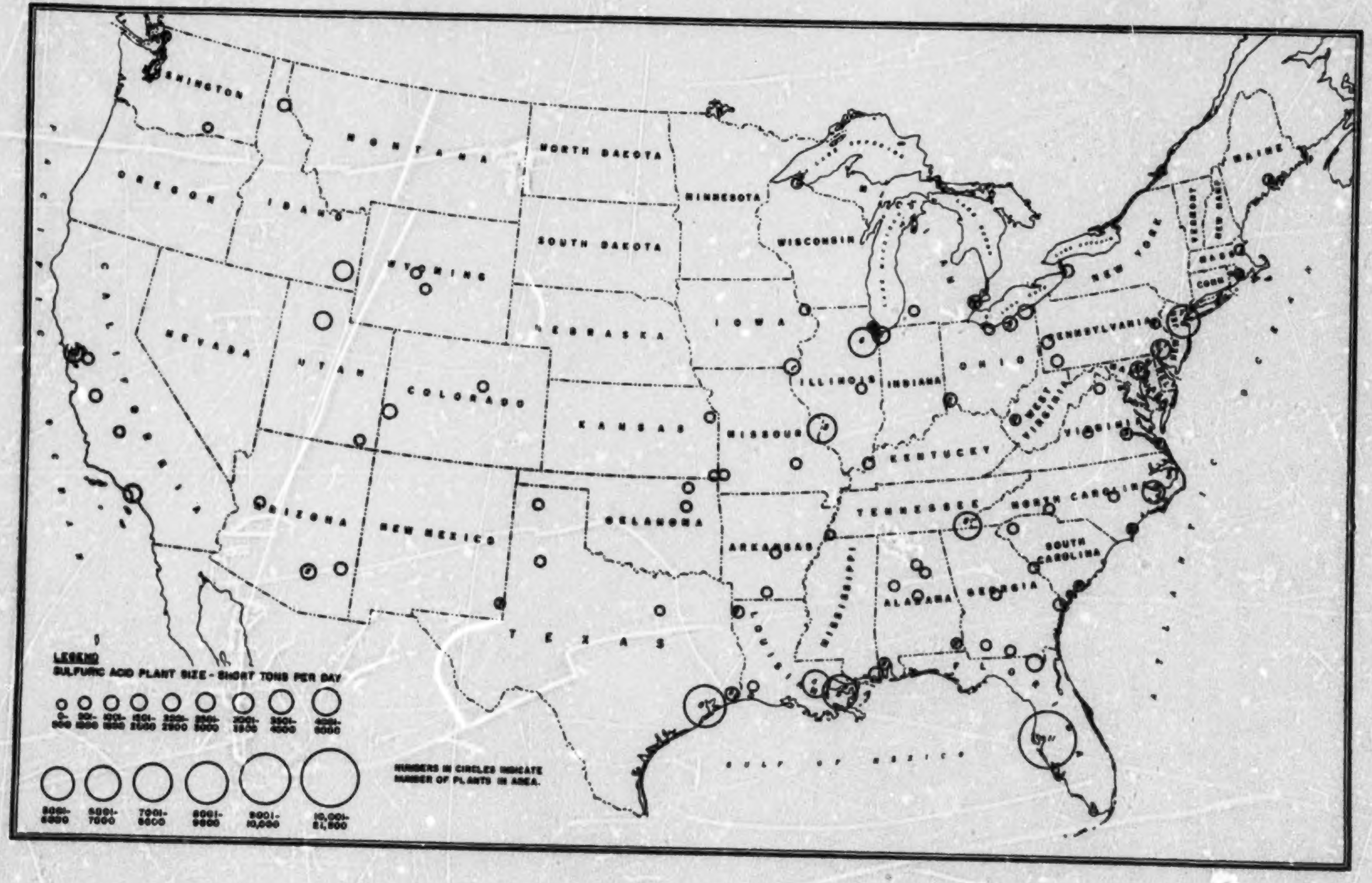
WASHINGTON
OREGON
CALIFORNIA
NEVADA
IDAHO
MONTANA
WYOMING
UTAH
COLORADO
ARIZONA
NEW MEXICO
NORTH DAKOTA
SOUTH DAKOTA
NEBRASKA
KANSAS
OKLAHOMA
TEXAS
MINNESOTA
IOWA
MISSOURI
ARKANSAS
LOUISIANA
WISCONSIN
ILLINOIS
INDIANA
MICHIGAN
OHIO
KENTUCKY
TENNESSEE
MISSISSIPPI
ALABAMA
GEORGIA
FLORIDA
SOUTH CAROLINA
NORTH CAROLINA
VIRGINIA
WEST VIRGINIA
PENNSYLVANIA
NEW YORK
VERMONT
NEW HAMPSHIRE
MAINE
MASS.
CONN.
PACIFIC OCEAN
ATLANTIC OCEAN
GULF OF MEXICO
LEGEND
SULFURIC ACID PLANT SIZE - SHORT TONS PER DAY
0-500
501-1000
1001-1500
1501-2000
2001-2500
2501-3000
3001-3500
3501-4000
4001-5000
5001-6000
6001-7000
7001-8000
8001-9000
9001-10,000
10,001-21,500
NUMBERS IN CIRCLES INDICATE NUMBER OF PLANTS IN AREA.

Figure 87. Sulfuric acid manufacturing capacity.

short in duration and supply soon exceeded demand, driving prices back down to recent lows.

Sulfuric acid is an excellent drying agent and is used in such applications as chlorine and nitric acid drying, DDT and chloral production, and in nitration reactions. The acid is an effective catalyst for many hydrocarbon and organic chemical syntheses, such as formations of petroleum alkylate from olefins and a paraffin, or the Beckman rearrangement of cyclohexane oxime to caprolactam for nylon fiber manufacture. It has been suggested that this characteristic is associated with its strong affinity for water. Sulfuric acid readily forms organic sulfates with many hydrocarbons which are easily hydrolized to yield desirable organics; this property is useful in the manufacture of pehnol and certain alcohols.

The acid has a high boiling point which limits volatilization losses in leaching, acidulation, and pickling operations. It is commonly specified as an electrolyte for batteries, used as a bath in cellulose processing, consumed in the manufacture of chromates, used in hydrogen fluoride production from fluorspar, and serves to process ore for titanium dioxide and uranium manufacture.

Sulfuric acid is made and used in a variety of concentrations which are usually indicated as follows:

% H_2SO_4 or °Baume–The simplest description of sulfuric acid concentration is % H_2SO_4. However, because of the distinct relationship between specific gravity and strength (up to 93%) and the simplicity of measuring specific gravity by hydrometer, most acid concentrations up to 93% are expressed as degrees Baume. From 93 to 100%, acids are referred to by concentration. These are the products assumed in this study.

Monohydrate–This is 100% H_2SO_4.

Oleum–Acids stronger than 100% H_2SO_4, containing free SO_3, are called oleums or fuming acids and are usually described in terms of SO_3 content. For example, a 20% oleum is comprised of 20% SO_3 and 80% H_2SO_4; however, in terms of acid content equivalent, it is expressed as 104.50% H_2SO_4. Oleum is not considered as a product in this study.

Table 64 shows a few typical acid strengths and their major end-uses (14).

A complete market study of a chemical such as sulfuric acid is beyond the scope of this report; however, to properly assess the economic potential of stack gas processes for sulfur dioxide recovery and conversion to acid, a limited investigation is included. Hopefully, in the near future, a thorough market study for sulfur products from power plants and smelter sources can be completed.

For basic economic evaluation, several items need specific coverage including market outlook, market location, best end-use market, and pricing policy. Although sulfuric acid is a large volume chemical with numerous outlets, difficulty will be encountered in marketing all of the acid produced from power plant stack gas at an attractive price. Furthermore, production volume, which is normally a prime variable in marketing, is set by the power plant size and all material produced must be disposed readily regardless of demand.

Currently, there are some spot shortages in the sulfuric acid industry (86) even though capacity is estimated at about 40 million tons/yr and consumption at only 30-31 million tons/yr. Several of the smaller plants have been shutdown recently due to production economics and environmental impact of SO_2 removal, and many of the new large (1,000 tpd and larger) units are captive, operating at rates matching internal demand. Although recent growth in acid consumption has slowed, the long range rate is estimated to be about 4-6%/yr which is closely tied to the fertilizer growth pattern.

At least for several years, both supply and price competition are expected to increase from sources of sulfur dioxide emission which are subject to increasingly tough air pollution laws. Both fossil-fueled power plants and western smelters are being pressed to clean up their emissions at a time when their respective products, electrical energy and non-ferrous metals, are undergoing rapid growth. At the same time, a rapidly growing need for clean fuels has resulted in an increase in natural gas production both in the U. S. and Canada, such that more and more byproduct sour gas sulfur is being made available for low cost sulfuric acid manufacture. Already, the Canadian sour gas operations are moving large tonnages of sulfur to market at prices as low as \$5-12/ton f.o.b. The natural gas is much more valuable than the byproduct sulfur and will continue to be produced regardless of value received for the sulfur.

Especially on the East Coast where byproduct sulfur is more expensive, Chemico reports that there is much interest by major sulfuric acid marketers to use offgas SO_2 as a raw material in place of elemental sulfur for acid manufacture. This interest particularly covers existing acid plants, many of which will require upgrading to meet new SO_2 emission standards. The construction of new and larger acid plants to replace a number of smaller and less efficient existing plants is also of considerable interest in a number of areas. The marriage of an acid plant and one or more power plants is attractive to both parties since these industries represent two of the most reliable and consistent types of operations in American industry with long life periods of 30-40 years. The acid plant requires a consistent source of sulfur values at competitive prices while the utility requires an assured home for the SO_2 it produces.

Location of the power plant equipped with a magnesia scrubbing process and producing sulfuric acid will have major influence on process economics (for location of major U. S. power plants burning coal or oil, see figure 88) (30). It is expensive to ship sulfuric acid very far, with 150-200 miles being a practical limit for most rail and truck

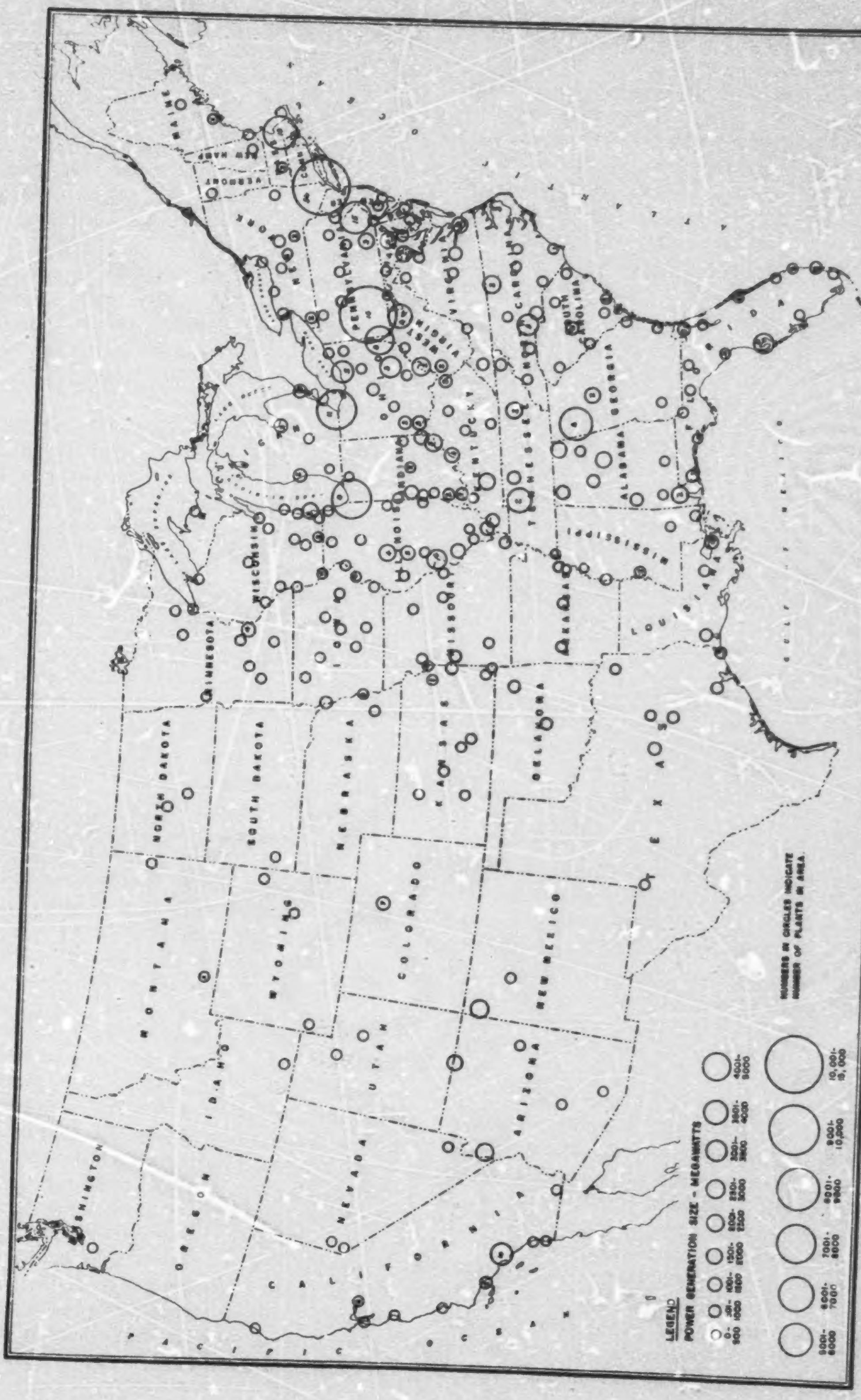
LEGEND
POWER GENERATION SIZE - MEGAWATTS
NUMBERS IN CIRCLES INDICATE NUMBER OF PLANTS IN AREA.
PACIFIC OCEAN
ATLANTIC OCEAN
GULF OF MEXICO
WASHINGTON
OREGON
CALIFORNIA
NEVADA
IDAHO
MONTANA
UTAH
ARIZONA
WYOMING
COLORADO
NEW MEXICO
NORTH DAKOTA
SOUTH DAKOTA
NEBRASKA
KANSAS
OKLAHOMA
TEXAS
MINNESOTA
IOWA
MISSOURI
ARKANSAS
LOUISIANA
WISCONSIN
ILLINOIS
MISSISSIPPI
INDIANA
KENTUCKY
TENNESSEE
ALABAMA
GEORGIA
FLORIDA
SOUTH CAROLINA
NORTH CAROLINA
VIRGINIA
WEST VIRGINIA
PENNSYLVANIA
NEW YORK
VERMONT
NEW HAMPSHIRE
MAINE

Figure 88. Location of major coal- and oil-fired power units—1971 (30).

Table 64. Typical sulfuric acid strengths and major end uses (14).

% H_2SO_4	° Be	% Oleum (% SO_3 content)	Uses[a]
35.67	30.8	–	Batteries
62.18-69.65	50-55	–	Normal superphosphate and fertilizers.
77.67	60.0	–	Normal superphosphate and fertilizers isoproply and secbutyl alcohols.
80.00	61.3	–	Copper leaching.
93.19	66.0	–	Phosphoric acid, TiO_2.
98-99	66.4-66.3[b]	–	Phosphoric acid, alkylation, ethyl alcohol, boric acid.
100.00	66.2[b]	–	Alkylation.
104.50	–	20	Caprolactam (Beckmann rearrangement); explosives and nitrations, chlorine and nitric acid drying; surface active agents, synthetic petroleum sulfonates, and other sulfonations; blending with weaker acids.
106.75	–	30	
109.00	–	40	
111.25	–	50	
113.50	–	60	
114.63	–	65	
122.50	–	100	

[a] These data do not imply that *only* the indicated concentrations are used for the applications shown.
[b] At concentrations approaching 100% H_2SO_4, specific gravity begins to decrease.

loads. For longer distances, acid could be shipped economically by barge. The major U. S. markets for sulfuric acid are concentrated on the East and Gulf Coasts. At present, the States of Florida, Louisiana, Texas, Illinois, and New Jersey consume close to half the U. S. total acid output with Florida taking one-quarter of the total. Waterways in these areas would allow transport of large quantities of acid for long distances at competitive prices. Similarly, it is possible to place a central processing plant some distance from the power units and incur transport costs for the MgO and $MgSO_3$ between the plants involved.

Florida is a major acid market since the reserves of phosphate rock are plentiful for fertilizer manufacture. Currently, sulfur is barged-in from Mexico, Texas, and Louisiana and with sulfur at $24/long ton f.o.b. and freight at $4-5/ton, Florida sulfuric acid can be produced for $10-15/short ton.

With such large quantities of acid as can be produced by a large power plant (378 tons/day, 500-mw, 3.5% S in coal) or central process acid complex (3000-mw equivalent, 2,000 tpd acid), the best end-use market appears to be the phosphate fertilizer industry. One of several devices could be utilized to improve economics, either long-term purchase contracts, on-site fertilizer plant adjacent to power plant, or barge shipments of product acid to large fertilizer complexes. The other end-use markets could be pursued also; however, such markets could place great pressures on single unit operation for a steady, continuous source of acid.

With the exception of Illinois, most of the large acid consuming areas are served by power plants fueled with oil or gas. In addition, nuclear plants are moving into Florida. The best location for a power plant equipped with a sulfuric acid producing system appears to be in the Midwest, preferably Illinois with its abundance of high sulfur coal. The Midwest, of course, consumes great quantities of phosphate fertilizer (54% of national consumption) and currently, intermediate phosphatic materials are shipped by barge from Florida to the Midwest; however, if low cost acid were available, it might be feasible to ship phosphate rock to the Midwest and process with local acid. Consumption statistics for phosphatic fertilizer in the midwestern states are shown in table 65 (90).

Assuming 2.7 tons of sulfuric acid/ton P_2O_5 (an average figure), approximately 10,980,000 tons of sulfuric acid could have been utilized in 1970 for phosphate fertilizers consumed in the listed states. This is equivalent to over 45,000-mw of power plant capacity.

Marketing sulfuric acid in large quantities requires some product flexibility; that is, more than one concentration of

Table 65. Consumption of phosphate fertilizers in the midwestern states (90).

State	1968	1969	(Prelim) 1970
	thousand tons P_2O_5		
Ohio	208	212	216
Indiana	284	253	243
Illinois	457	497	528
Michigan	128	123	127
Wisconsin	116	121	120
Missouri	165	160	171
Iowa	361	382	405
Minnesota	214	292	223
Total	**3,866**	**4,080**	**4,066**

acid should be available for sale. Indications are that three concentrations dominate 80% of the market, 60° Be (78%), 66° Be (93%), and 98%. Any plant producing for the merchant market (non-captive) would probably need minimum storage facilities for three products for 30 days.

In addition to storage needs, 70-75 tank cars or several barges would be required to transport the production of a 500-mw power unit to market. If these cars or barges can be purchased or leased on a long-term basis, shipping costs in the range of $1-2/ton can sometimes be achieved. Estimated commercial shipping costs for sulfuric acid moved by rail and truck for Chicago and Philadelphia locations are shown in table 66.

Current 1972 list prices for tank car quantities of sulfuric acid (100% basis) range from $30-34/ton. Usually, these prices are discounted for volume consumers to a range of $20-28/ton, 100% acid. Although some quantities from a power plant may be disposed of at these prices, the volumes produced by large power units will result in a pricing policy somewhat less dependent on current market values. The major factors affecting the pricing policy of byproduct sulfuric acid are:

1. Area competitive forces.
2. The cost of sulfur to existing plants.
3. The flexibility of acid unit operation to match demand.

In addition, as with any sulfuric acid market, the distances of customers from available acid sources will influence net revenue to the manufacturer. For a midwestern location, current prices of sulfur from the Gulf Coast would permit an acid manufacturing cost of $12-16/ton, whereas Canadian sulfur at $5-8/long ton and freight costs of $14-16/ton would yield an acid cost of $10-14/ton. These values include capital charges which, if neglected for those plants operating on margin only, would reduce acid values to $8-10 minimum f.o.b. cost.

For midwestern acid producers, the stiffest competition for sale of sulfuric acid to fertilizer plants would be the processing and shipment of fertilizers from Florida. For phosphate rock to be shipped to the Midwest for acidulation and the resultant products to remain competitive with the processed material from Florida, sulfuric acid from midwestern power plants would need to be available for about $4-11/ton delivered. This means that the fertilizer plant needs to be close to the acid plant to minimize transportation costs.

For purposes of this study, it will be assumed that for the first 10 years of operation, the net sales revenue (revenue after all sales and shipping expense deducted) for acid consumed in all markets averages $8/ton when supplied from single-site power-acid systems. To give more complete coverage, this value will be subjected to sensitivity analysis in the economic evaluation by varying the net sales revenue from $0-32/ton. In addition, after the tenth year of operation, net sales revenue will be assumed to drop to $5/ton due to the increasing competition from other byproduct sources of acid.

Table 66. Sulfuric acid shipping costs.

Published rail shipping rates for sulfuric or spent sulfuric acid in tank cars, minimum weight rule 35, but not less than 140,000 lbs per car. From Philadelphia, Pennsylvania, and Chicago, Illinois

To (miles)	Rate in cents/net ton[a]
25	225[b]
50	251[b]
100	397
150	633
300	1,127

Estimated private costs for shipping sulfuric acid in tank trucks.[c] From Philadelphia, Pennsylvania and Chicago, Illinois

To (miles)	Cost in cents /net ton
25	300[d]
50	300
75	375
100	500
150	750
300	1,500

[a] Rates lower than those shown may be published from Philadelphia or Chicago to specific destinations in any given mileage category. As an illustration, rate of 625 cents/net ton, minimum weight 140,000 lbs is published from Chicago to Wood River, Illinois (276 miles), restricted to apply only on movement of sulfuric acid, the virgin acid to the point of distribution and the spent acid in return from point of distribution to origin for processing, and so certified on bill of lading.

[b] Subject to minimum rate of 383 cents per net ton per car, on traffic originating at or destined to points *in the Chicago switching district*. This minimum of 383 cents per net ton does not apply on movements where the origin and destination are both outside the Chicago switching district.

[c] Estimated on basis of 60 cents per mile for distances of 50 miles or less and 50 cents per mile for distances over 50 miles. Cents are calculated on round trip mileage, assuming load of 40,000 lbs in one direction and an empty return in the other direction.

[d] Estimated minimum cost, based on charges presently published by commercial carriers.

It is entirely probable that the acid produced in central acid processing systems (Scheme D) would command a higher price than for inflexible single-site systems. Assuming better choice of location and flexible operating rates, a net sales revenue averaging $12/ton is predicted for the 10 years of central process unit life.

Regulated Economic Evaluation

The basic premise of regulated economics ascribes that the power company will be permitted to charge electricity customers sufficiently to earn up to a prescribed return on base investment. Since electrical power producers rarely compete with each other in a given geographical area, regulation of power rates is necessary to prohibit unreasonable profits, but at the same time assure an adequate return on investment sufficient to attract capital for expansion to meet growing demand. In the United States, regulation is usually the responsibility of state or local agencies with the Federal Power Commission responsible for setting guidelines for accounting procedures and for rates on interstate transactions.

If a power company provides all or a portion of the investment for pollution abatement facilities, its investment will almost certainly be merged with the total power plant investment as is presently done with dust removal equipment and, therefore, increase the "rate base" on which the utility is allowed to earn at the rate set by the regulatory commission. Thus, a return on equity or profit must be included in any process evaluation under regulated economics; it is the "cost of money" as any other operating cost item such as fuel or labor.

As with previous conceptual design studies, the regulated "cost of money" is added to operating costs as part of the capital charges applied (see table 47 of Investment and Operating Cost section). For nonrecovery processes, a direct comparison of total operating costs will generally serve as a means of process evaluation; however, sales revenue must be recognized for processes producing a product. In addition, the annual operating cost will vary each year as the rate base declines due to depreciation "write off" (the cost of money and income taxes are applied to undepreciated portion of investment) and with any changes in onstream time of the power unit; therefore, it is desirable to have a year-to-year tabulation of operating costs for any given case. Furthermore, recognizing the time value of money, these annual operating costs should be discounted at the cost of money (10% for this study) to the initial year of operation for ready comparison of present worth to other pollution control means such as the annual costs required for low sulfur fuels.

Since rate of investment profitability is prescribed under regulated economics, the data generated by the tabulation of operating costs only indicate which process or method of pollution abatement yields the minimum cost to the consumer. Depending on the achievable net sales revenue, the process or method used will either increase or decrease the cost of power to the consumer.

Tables A-95 to A-132, presented in Appendix A, are computer printouts which show year-to-year operating costs under regulated economics, projected sales revenue, and the resultant cost effect on power consumers for the 29 magnesia Scheme A, B, and C cases over their expected project life. Included in these tables are comparable limestone-wet scrubbing operating costs with examples shown for both the low and high cost variations. Actual outlay values are given for each year along with the discounted and actual cumulative total costs and unit costs either per ton of coal burned, per barrel of oil burned, or mills per kilowatt hour. A summary of these results is shown in table 67 for the 30-year life of new 200-mw, 500-mw, and 1000-mw units burning coal containing 3.5% S or oil containing 2.5% S. Shown in table 68 is a comparison of cumulative present worth of magnesia and limestone costs over the project life for several other coal- and oil-fired unit case variations.

These results are shown graphically in figures 89 and 90 which describe the effect of power unit size on cumulative present worth of the total and unit change in the cost of power over the life of new coal-fired units utilizing either the magnesia schemes or limestone-wet scrubbing for SO_2 removal. Figure 91 describes the same effect for oil-fired units. With acid sales revenue at $8/ton, the costs of the magnesia schemes are between the extremes of the limestone-wet scrubbing process; however, at low unit sizes, the magnesia Scheme A and B costs are greater than the high cost limestone example. As unit size increases, the magnesia schemes become much more competitive. Table 69 gives the acid sales revenue per ton required for each magnesia scheme to yield the same overall cost as the limestone-wet scrubbing examples.

Displayed in figures 92 and 93 is the effect of sulfur content of coal and oil on the change in cost of power due to magnesia Scheme A and limestone-wet scrubbing.

The effect of 7,000 hrs/yr of constant operating time over the life of the power unit can be seen in figures 94 and 95. These values should be compared to those in figures 89 and 90 which represent the declining onstream pattern. Another interesting point can be examined in figure 96 which describes the change in cost of power for power units of varying remaining life and years of 7,000 hour operation. The operating period for the existing units is assumed to follow the same schedule as for new units, with the number of years of 7,000 hour operation being the only period reduced.

The relationship of fixed investment on net cost is shown in figures 97 and 98 using sensitivity analysis of investment for Scheme A on coal- and oil-fired systems.

Shown in figures 99 and 100 are the cumulative total and unit cost effects of variations in net sales revenue for single-site Scheme A. For Scheme A to yield the same increase in cost of power as the low cost limestone-wet scrubbing example, a revenue of approximately $16-20/ton of acid would have to be realized. This is slightly lower than the current going f.o.b. price of acid marketed by existing producers. When compared to the high cost wet limestone example, the magnesia Scheme A does not need any revenue from acid sales to be competitive.

Most of the operating cost estimates given in this report reflect no labor cost escalation over the life of the system;

Table 67. Actual and discounted cumulative total and unit increase (decrease) in the cost of power for magnesia schemes and limestone-wet scrubbing process under regulated economics.[a]

Coal fired	Actual cumulative net increase (decrease) in cost of power			Cumulative present worth of net increase (decrease in cost of power, discounted at 10%/yr		
3.5% S in coal	$	$/ton coal	Mills/kwh	$	$/ton coal	Mills/kwh
Scheme A						
200-mw	91,134,900	9.32	3.57	36,354,900	3.72	1.43
500-mw	162,116,800	6.78	2.54	64,708,000	2.71	1.02
1,000-mw	237,884,900	5.15	1.87	94,910,200	2.05	0.74
Scheme B						
200-mw	93,043,200	9.52	3.65	37,116,300	3.80	1.46
500-mw	165,231,600	6.91	2.59	65,952,600	2.76	1.03
1,000-mw	242,437,200	5.25	1.90	96,743,000	2.09	0.76
Scheme C						
200-mw	79,368,200	8.12	3.11	31,679,000	3.24	1.24
500-mw	139,009,800	5.81	2.18	55,530,300	2.32	0.87
1,000-mw	203,777,400	4.41	1.60	81,383,500	1.76	0.64
Limestone-wet scrubbing–low limestone cost, on-site solids disposal						
200-mw	72,059,000	7.44	2.85	29,257,300	2.99	1.15
500-mw	136,225,900	5.70	2.14	54,984,900	2.30	0.86
1,000-mw	208,272,000	2.51	1.63	84,316,100	1.82	0.66
Limestone-wet scrubbing–high limestone cost, off-site solids disposal						
200-mw	82,657,700	8.46	3.24	33,873,300	3.47	1.33
500-mw	170,642,600	7.14	2.68	70,296,800	2.94	1.10
1,000-mw	283,172,800	6.13	2.22	117,261,000	2.54	0.92
Oil fired						
2.5% S in oil	$	$/bbl oil	Mills/kwh	$	$/bbl oil	Mills/kwh
Scheme A						
200-mw	54,382,100	1.45	2.13	21,670,900	0.58	0.85
500-mw	95,922,800	1.05	1.50	38,313,300	0.42	0.60
1,000-mw	141,598,400	0.80	1.11	56,611,200	0.32	0.44
Scheme B						
200-mw	54,061,700	1.44	2.12	21,510,000	0.57	0.84
500-mw	94,233,700	1.03	1.48	37,564,700	0.41	0.59
1,000-mw	138,611,000	0.78	1.09	55,284,000	0.31	0.43
Limestone-wet scrubbing–low limestone cost, on-site solids disposal						
200-mw	46,352,800	1.24	1.82	18,625,500	0.50	0.73
500-mw	84,224,500	0.92	1.32	34,007,700	0.37	0.53
1,000-mw	129,543,900	0.73	1.02	52,482,100	0.30	0.41
Limestone-wet scrubbing–high limestone cost, off-site solids disposal						
200-mw	47,671,000	1.27	1.87	19,409,800	0.52	0.76
500-mw	94,255,700	1.03	1.48	38,632,900	0.42	0.61
1,000-mw	154,350,700	0.87	1.21	63,589,800	0.36	0.50

[a] Over 30 yr power unit life.

however, this is probably not realistic. To show the effect of labor cost escalation over the life of the unit at different annual rates of increase, figure 101 is presented. Because labor costs for most SO_2 removal processes are comparable, the exclusion of an escalation rate does not radically affect process evaluation.

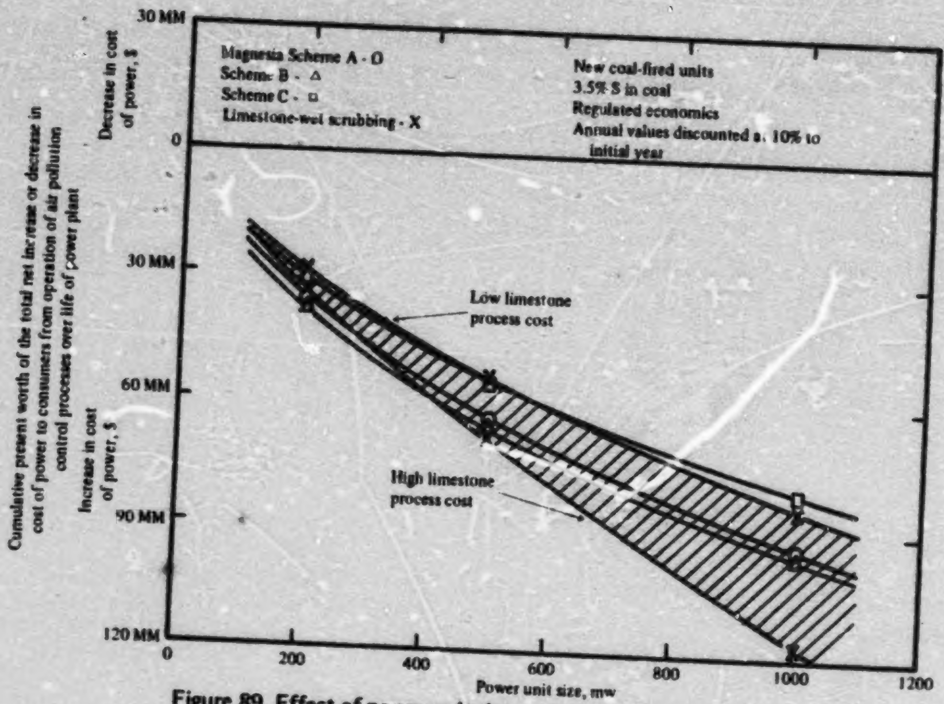

Figure 89. Effect of power unit size on cumulative present worth of total net increase or decrease in the cost of power to consumers for coal-fired power units using magnesia schemes.

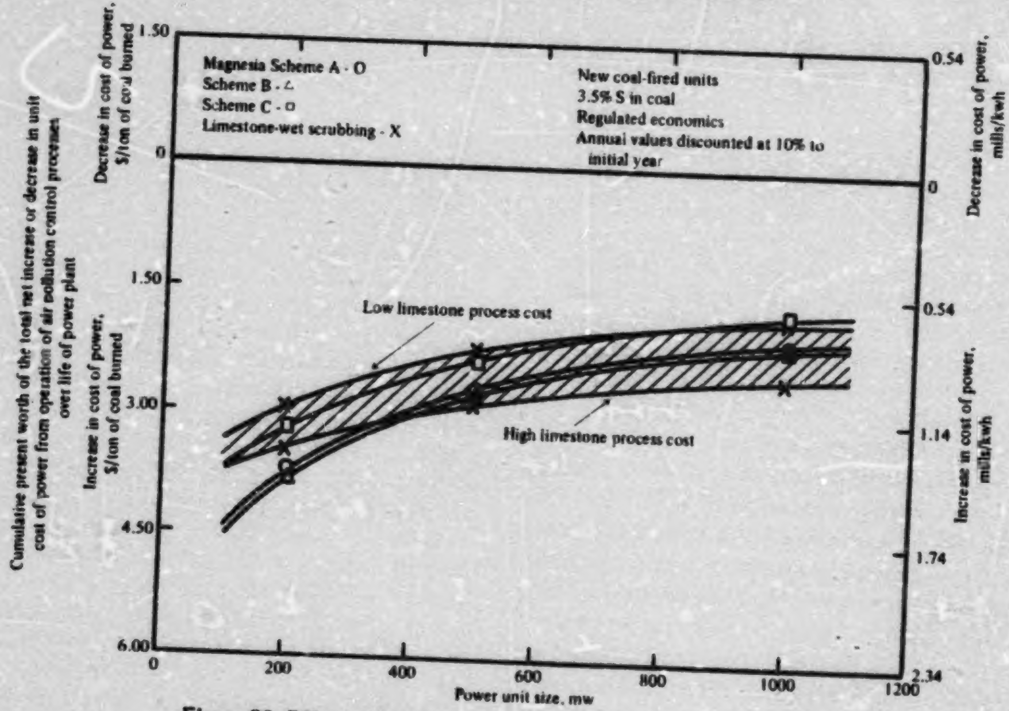

Figure 90. Effect of power unit size on cumulative present worth of unit increase or decrease in the cost of power to consumers for coal-fired power units using magnesia schemes.

Table 68. Comparison of present worth of cumulative total and unit increase (decrease) in cost of power for case variations of magnesia Scheme A and limestone-wet scrubbing processes under regulated economics.[a]

Cases	Magnesia process Present worth of net increase (decrease) in cost of power			Limestone-wet scrubbing process Low limestone cost, on-site solids disposal Present worth of net increase (decrease) in cost of power			Limestone-wet scrubbing process High limestone cost, off-site solids disposal Present worth of net increase (decrease) in cost of power		
Coal fired	$	$/ton coal	Mills/kwh	$	$/ton coal	Mills/kwh	$	$/ton coal	Mills/kwh
Scheme A									
200-mw E 3.5% S	34,079,300	6.02	2.38	27,307,600	4.82	1.91	29,700,800	5.25	2.08
500-mw N 2.0% S	56,387,000	2.36	0.88	49,407,100	2.07	0.78	59,934,100	2.51	0.94
500-mw N 5.0% S	71,813,900	3.00	1.13	59,995,400	2.51	0.94	80,351,300	3.36	1.26
500-mw E 3.5% S	68,678,700	3.36	1.29	57,749,700	2.83	1.08	71,875,200	3.52	1.35
1,000-mw E 3.5% S	98,600,300	2.47	0.93	87,046,700	2.18	0.82	118,354,600	2.96	1.11
Oil fired	$	$/bbl oil	Mills/kwh	$	$/bbl oil	Mills/kwh	$	$/bbl oil	Mills/kwh
Scheme A									
200-mw N 1.0% S	16,807,100	0.45	0.66	16,221,100	0.43	0.64	16,024,900	0.43	0.63
200-mw N 4.0% S	25,230,000	0.67	0.99	20,682,100	0.55	0.81	22,684,400	0.61	0.89
200-mw E 2.5% S	20,155,600	0.93	1.41	17,862,000	0.82	1.25	17,878,200	0.82	1.25
500-mw N 1.0% S	31,092,000	0.34	0.49	29,653,900	0.32	0.47	30,902,700	0.34	0.48
500-mw N 4.0% S	44,197,900	0.48	0.69	37,916,800	0.41	0.59	46,211,700	0.50	0.72
500-mw E 2.5% S	40,215,400	0.51	0.76	36,435,400	0.47	0.68	40,622,200	0.52	0.76
1,000-mw N 1.0% S	45,980,700	0.26	0.36	45,517,600	0.26	0.36	49,293,200	0.28	0.39
1,000-mw N 4.0% S	64,717,200	0.37	0.51	58,833,700	0.33	0.46	77,761,400	0.44	0.61
1,000-mw E 2.5% S	58,523,000	0.38	0.55	54,890,100	0.36	0.52	65,428,700	0.43	0.61

[a] Over previously defined power plant life.

Nonregulated Economic Evaluation

If chemical companies or other nonregulated business groups enter into sulfuric acid production by using a magnesia scrubbing-regeneration process on a power unit, either contributing all or part of the required investment, profitability of the venture becomes of paramount importance. A nonregulated company, with no guarantee of income or profitability and with all the uncertainties associated with the future pricing of sulfur and related products, must be able to see promise of a competitive rate of return to justify capital expenditures on such a project.

The cost of recovering sulfur oxides as sulfuric acid and the expected sales revenue of the acid have been estimated previously. For single-site applications, one other source of income can also be considered; namely, a payment by the power producer to the chemical company for performing the service of pollution abatement. This seems reasonable since the power company must incur a considerable cost in any event for reducing the sulfur oxides in the gas (by either purchasing low sulfur fuel at a premium, or contributing necessary capital for the project itself).

The amount of payment presumably would be negotiated between the two companies, and could range from zero to the full cost of alternate throwaway processes such as limestone-wet scrubbing. Again, there are several alternatives available to a power company; however, the cost of the limestone-wet scrubbing process can be varied by the same parameters as recovery processes; therefore, it should serve as a reasonable measure of possible payment. Hence, the profitability estimates under nonregulated economics have been calculated on three bases—full payment equivalent to either high or low cost limestone-wet scrubbing and no payment. In practice, the expected payment could be almost anywhere between the high equivalent payment and none at all.

The question regarding the attractiveness of a process for chemical industry investment can be answered best by applying a venture appraisal method that relates profit-making potential to the investment requirements. Several types of venture appraisal techniques are used in nonregulated industry; three of the more common ones (annual return on initial investment, payout period, and interest rate of return) have been calculated for all applicable cases where nonregulated industry economics are involved. The

Table 69. Required unit sales revenue for sulfuric acid to equalize magnesia and limestone scrubbing process costs.

Cases	Net sales revenue $/ton of acid	
	Low limestone cost, on-site solids disposal	High limestone cost, off-site solids disposal
Coal fired		
Scheme A		
200-mw N 3.5% S	29.03	16.94
200-mw E 3.5% S	37.35	29.29
500-mw N 2.0% S	22.50	1.86
500-mw N 3.5% S	19.52	2.41
500-mw N 5.0% S	17.78	1.86
500-mw E 3.5% S	22.42	5.60
1,000-mw N 3.5% S	14.26	[a]
1,000-mw E 3.5% S	15.69	[a]
Scheme B		
200-mw N 3.5% S	31.34	19.26
500-mw N 3.5% S	21.07	3.96
1,000-mw N 3.5% S	15.43	[a]
Scheme C		
200-mw N 3.5% S	16.09	1.98
500-mw N 3.5% S	8.26	[a]
1,000-mw N 3.5% S	5.30	[a]
Oil fired		
Scheme A		
200-mw N 1.0% S	15.79	20.04
200-mw N 2.5% S	24.94	21.93
200-mw N 4.0% S	23.79	18.12
200-mw E 2.5% S	26.61	28.29
500-mw N 1.0% S	15.97	10.06
500-mw N 2.5% S	17.56	8.20
500-mw N 4.0% S	16.67	6.04
500-mw E 2.5% S	17.25	8.35
1,000-mw N 1.0% S	8.85	[a]
1,000-mw N 2.5% S	12.46	0.50
1,000-mw N 4.0% S	11.93	[a]
1,000-mw E 2.5% S	12.39	0.43
Scheme B		
200-mw N 2.5% S	24.21	21.20
500-mw N 2.5% S	16.05	6.63
1,000-mw N 2.5% S	11.02	[a]

[a] Magnesia scrubbing operating cost without sulfuric acid revenue is less than limestone scrubbing cost.

annual return on investment is defined as the annual net income after taxes divided by the initial total investment including working capital; the composite tax rate for nonregulated industry is assumed to be 50% of gross income. Payout period is the number of years required to recover the initial investment by cash flow (depreciation plus net income after taxes). Interest rate of return, often referred to as discounted cash flow, is best described as the interest rate at which the sum of the present worth of the yearly receipts (depreciation plus after-tax profit) becomes equal to the sum of the present worth of the disbursements. Another definition is the interest rate a savings bank would have to pay to accept and return cash on the same schedule as the proposal. Of the three methods, only interest rate of return recognizes the time value of money.

It is difficult to say what degree of profitability is large enough to attract chemical investors to the magnesia process since each company has its own criteria as to what is considered an attractive venture; no standard can be set. However, a rough concensus for new chemical ventures appears to be greater than 10% annual return on investment after taxes, 15% interest rate of return after taxes and a payout in less than 6 years. For an established industry such as sulfuric acid, such profitability is not often attained except through captive use markets where a more valuable end product can justify higher profitability. More reasonable values might be 7-10% annual return after taxes, 12-15% interest rate of return after taxes, and 5-6 years payout. These guides should help in examining the results of this evaluation.

The results of the profitability analysis under nonregulated economics are presented for each case as computer printouts in Appendix A (tables A-133 to A-176). The printouts describe each year of operation including yearly operating costs for the prescribed periods, net sales revenue, gross and net income, and the annual cash flow over the power unit life. Payout periods and interest rates of return, with high and low equivalent payment and without any payment, are shown for each case. These values are summarized in table 70.

The data indicate that without a payment for air pollution control equivalent to the high cost limestone-wet scrubbing process, at $8/ton of acid, the magnesia scrubbing-regeneration schemes are not at all attractive; in fact, they have a negative interest rate of return when there is no payment. With the higher payment, however, the units 500-mw and larger show sufficient promise to possibly attract chemical industry investment.

To fully consider the results, several graphs have been prepared describing the effects of particular variables. The effect of power unit size on the payout period and interest rate of return for coal-fired units are given in figures 102 to 107. The data compares Schemes A, B, and C, indicating that best results are obtained with Scheme C. Similar results for oil-fired units are shown in figures 108 to 111 indicating Scheme B to be slightly better than Scheme A. For single-site situations, increasing power unit size shows only moderate improvement in economic profitability.

Figures 112 to 115 describe the effect of sulfur content of fuel on profitability for oil- and coal-fired power units. As the sulfur content of fuel increases, profitability is not

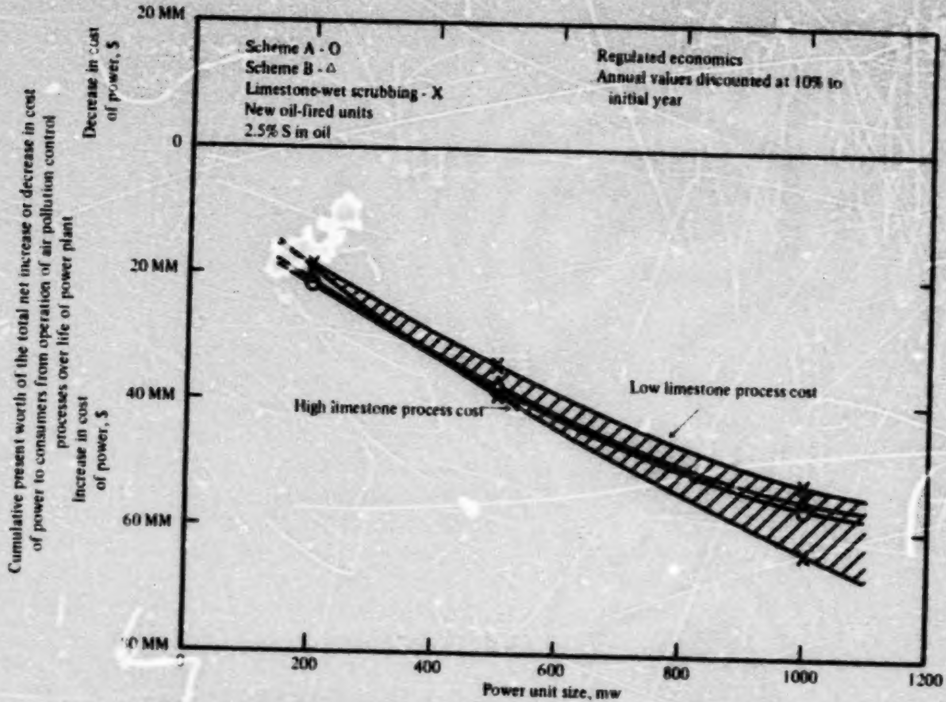

Figure 91. The effect of power unit size on cumulative present worth of total net increase or decrease in the cost of power to consumers for oil-fired power units using magnesia schemes.

radically altered indicating that incremental production costs are just offset by incremental revenue when acid is sold for $8/ton net back. If the acid could be marketed at values higher than incremental operating costs, profitability would be noticeably improved.

The effect of net sales revenue for sulfuric acid can be seen in figures 116 to 119 covering Scheme A, coal-fired units with sales revenue ranging from 0 to 400% ($0-32/ton) of the $8/ton base value. Graphs are shown for cases including both high and low payments equivalent to limestone-wet scrubbing. If revenue of $20-30/ton could be obtained and coupled with the high equivalent limestone-wet scrubbing payment, all sizes of the magnesia process would be attractive as a means of acid manufacture.

Varying expected fixed investment requirements for Scheme A on coal-fired units yields the results shown in figures 120 and 121. It can be seen that reduction in forecasted investment could increase profitability to acceptable levels.

The effect of onstream time is described in figure 122 which gives payout of various Scheme A unit sizes for either 7,000 hours or 5,000 hours annual operation over the 30-year life of the unit. When the high equivalent payment is negotiated, higher onstream time is quite helpful toward improving profitability. The influence of unit status or age on interest rate of return, with appropriate reduction in years of 7,000 hour operation, is displayed in figure 123. As remaining onstream time declines, alternatives requiring very little capital investment such as low sulfur fuel are better choices.

The reduction in interest rate of return and increase in payout period for varying rates of labor cost escalation over the 30-year operating period are given for Scheme A, 500-mw coal-fired units in figures 124 and 125. If the payments for air pollution control are also escalated, the change in profitability would be negated.

Cooperative Economics—Central Processing Concept

Thus far, the profitability potential of single-site, magnesia scrubbing-regeneration systems has been evaluated by assuming that the total process investment requirements are provided by either a regulated power company or a nonregulated chemical company and by using the appropriate economic evaluation technique. It is possible, however, to have combinations of the two types of economics if a power company and a chemical company each provide a portion of the investment needs of single or multiple systems. Probably the simplest of such cooperative

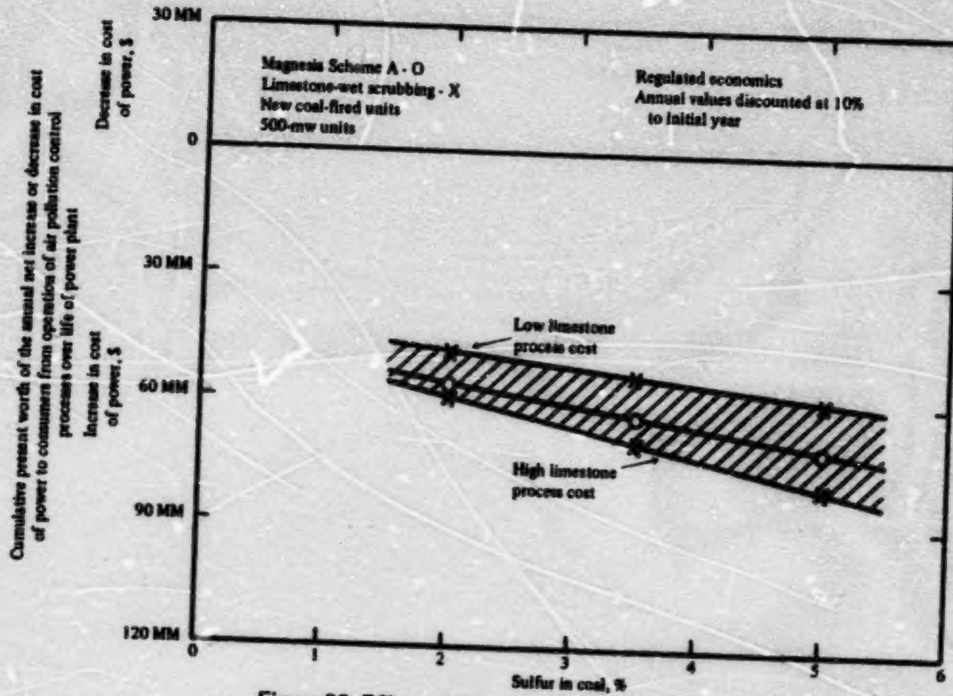

Figure 92. Effect of sulfur content of coal on cumulative present worth of total net increase or decrease in the cost of power to consumers for magnesia Scheme A.

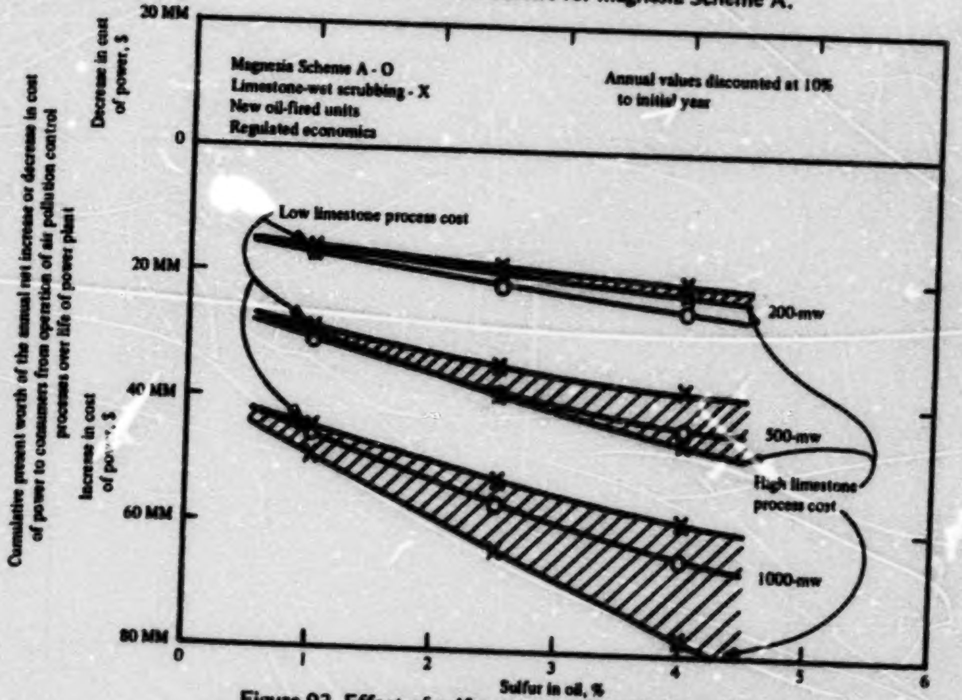

Figure 93. Effect of sulfur content of oil on cumulative present worth of total net increase or decrease in cost of power to consumers for magnesia Scheme A.

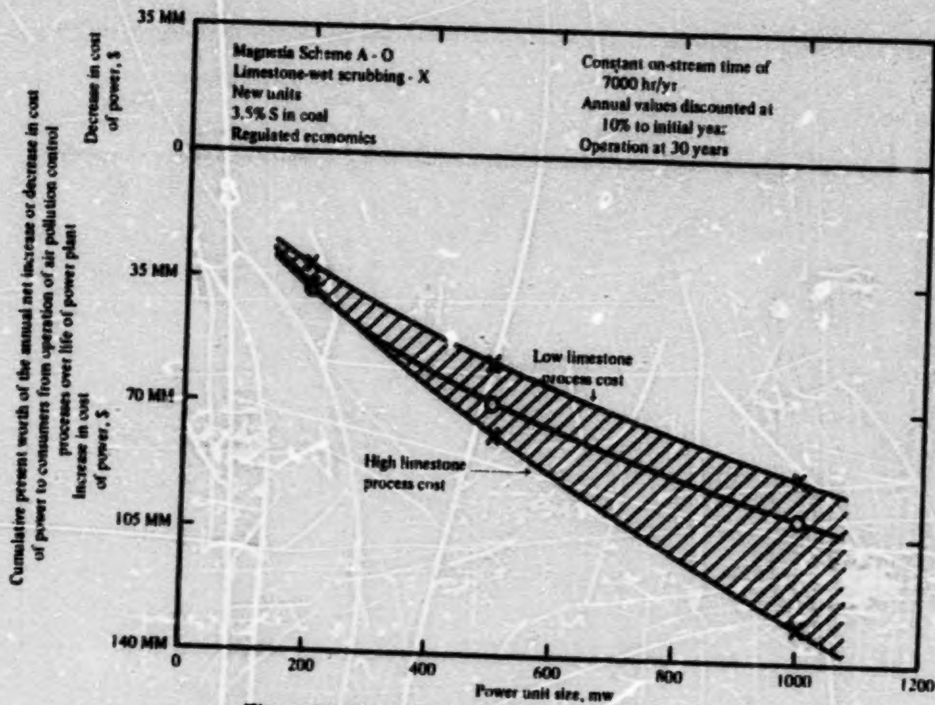

Figure 94. Effect of constant onstream time of 7,000 hr/yr on cumulative present worth of total net increase or decrease in cost of power to consumers for coal-fired units using magnesia Scheme A.

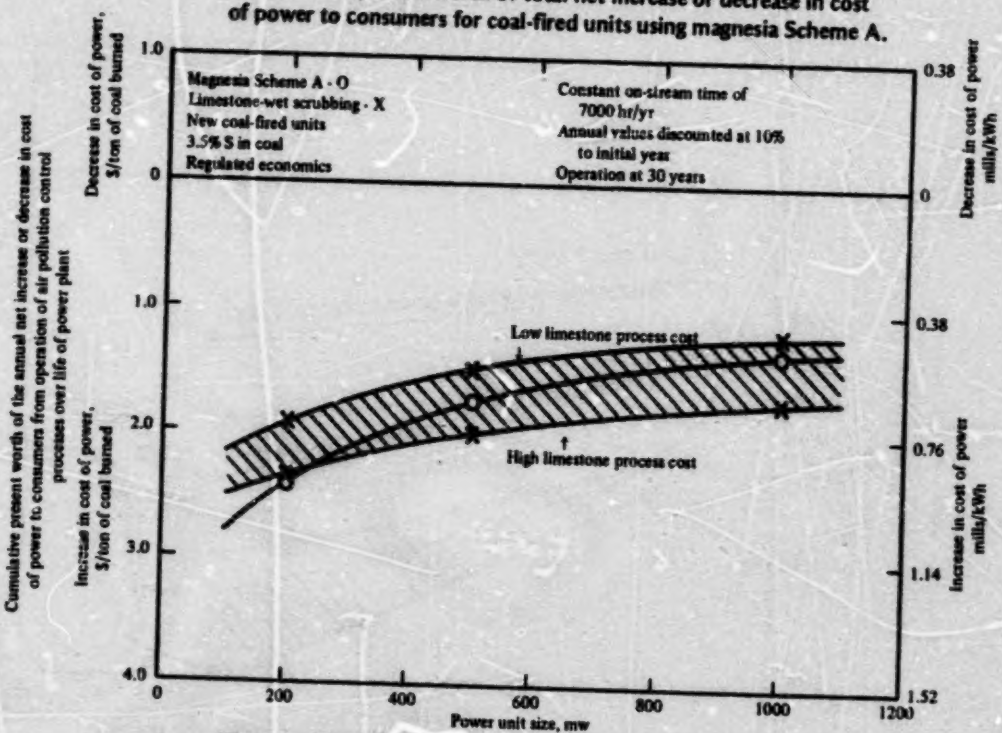

Figure 95. Effect of constant onstream time of 7,000 hr/yr on cumulative present worth of unit increase or decrease in cost of power to consumers for coal-fired units using magnesia Scheme A.

Table 70. Economic potential of magnesia scrubbing-regeneration schemes under nonregulated economics.

Cases	With payment equivalent to[a]				Without payment	
	Low limestone cost, on-site solids disposal		High limestone cost, off-site solids disposal			
	Payout yr	Interest rate of return, %	Payout yr	Interest rate of return, %	Payout yr	Interest rate of return, %
Coal fired						
Scheme A						
200-mw N 3.5% S	8.3	7.4	6.7	11.0	None	Neg.
200-mw E 3.5% S	8.2	6.6	7.2	8.5	None	Neg.
500-mw N 2.0% S	7.4	9.5	5.7	14.3	None	Neg.
500-mw N 3.5% S	7.6	8.8	5.6	14.9	None	Neg.
500-mw N 5.0% S	7.7	8.5	5.4	15.7	None	Neg.
500-mw E 3.5% S	7.7	8.4	5.7	13.6	None	Neg.
1,000-mw N 3.5% S	7.1	10.0	4.8	18.1	None	Neg.
1,000-mw E 3.5% S	7.1	9.6	4.9	17.1	None	Neg.
Scheme B						
200-mw N 3.5% S	8.5	6.9	6.9	10.5	None	Neg.
500-mw N 3.5% S	7.8	8.4	5.7	14.4	None	Neg.
1,000-mw N 3.5% S	7.3	9.6	4.9	17.6	None	Neg.
Scheme C						
200-mw N 3.5% S	6.9	10.7	5.6	14.6	None	Neg.
500-mw N 3.5% S	6.2	12.5	4.6	19.2	None	Neg.
1,000-mw N 3.5% S	5.9	13.6	4.0	22.8	None	Neg.
Oil fired						
Scheme A						
200-mw N 1.0% S	6.5	11.8	6.6	11.5	None	Neg.
200-mw N 2.5% S	7.6	8.8	7.1	9.9	None	Neg.
200-mw N 4.0% S	8.1	7.7	7.0	10.0	None	Neg.
200-mw E 2.5% S	7.3	8.8	7.1	8.8	None	Neg.
500-mw N 1.0% S	6.6	11.5	6.2	12.6	None	Neg.
500-mw N 2.5% S	7.2	9.8	6.1	13.0	None	Neg.
500-mw N 4.0% S	7.5	9.0	5.8	14.0	None	Neg.
500-mw E 2.5% S	7.0	10.0	6.0	12.7	None	Neg.
1,000-mw N 1.0% S	6.3	12.4	5.7	14.5	None	Neg.
1,000-mw N 2.5% S	6.8	10.9	5.3	15.8	None	Neg.
1,000-mw N 4.0% S	6.9	10.5	4.9	17.6	None	Neg.
1,000-mw E 2.5% S	6.7	10.9	5.3	15.3	None	Neg.
Scheme B						
200-mw N 2.5% S	7.5	9.1	7.0	10.1	None	Neg.
500-mw N 2.5% S	7.0	10.3	5.9	13.5	None	Neg.
1,000-mw N 2.5% S	6.6	11.5	5.2	16.2	None	Neg.

[a] Payment from power company to chemical company for SO_2 removal—equivalent to comparable limestone-wet scrubbing process costs.

arrangements would be for the power company to finance the scrubbing-drying operations and the chemical company to provide capital for the regeneration-acid manufacturing facilities. Each company would then be responsible for only its portion of activity; that is, the power company for particulate and sulfur dioxide removal, and the chemical company for acid disposal. Under this arrangement the power companies would supply magnesium sulfite to the chemical company and would receive regenerated magnesium oxide. The power company would be involved only in the sale of power under regulated economics and the chemical company would handle the sale of sulfuric acid or other products under nonregulated economics.

Even though single-site operations could function under such arrangements, the most promising application of a cooperative venture would be the central processing concept where several power units at separate sites independently provide the magnesium sulfite for a central

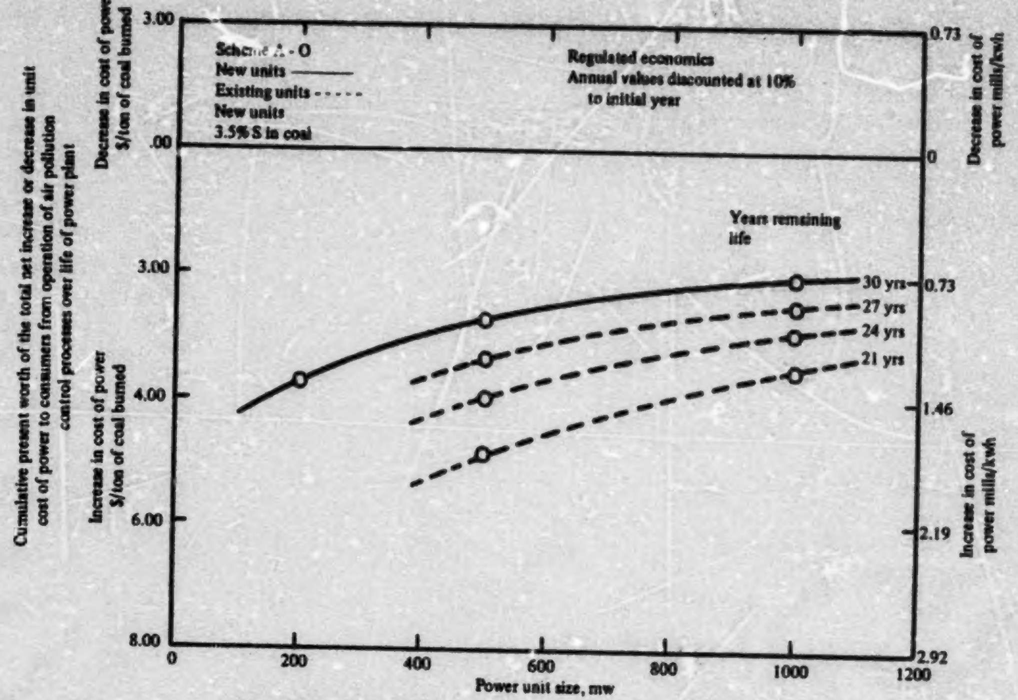

Figure 96. Effect of plant age or status on cumulative present worth of unit increase or decrease in the cost of power to consumers for coal-fired plants using magnesia Scheme A.

regeneration-acid unit. As discussed earlier, the principal differences between costs for single-site operation and the central process concept would be in material shipping costs between locations, the economy of scale of regeneration-acid manufacture, and the independent operating stream time and flexibility of the regeneration-acid plant. Using the previously developed concept of operating costs under cooperative economics, the profitability of the power company is maintained and the profitability of the chemical company can be examined by conventional means.

Profitability evaluation of the central processing concept under cooperative economics requires some modifications in the assumptions made previously under operating cost and nonregulated profitability evaluation. In comparing results presented in tables 56 and 59 of the Investment and Operating Cost section, it can be seen that the regulated, annual operating cost for magnesia Scheme D scrubbing-drying systems on new, coal-fired units are less than even low cost limestone-wet scrubbing systems ($2,498,900 vs $2,869,200 at 200-mw; $4,665,300 vs $5,376,300 at 500-mw; and $7,409,300 vs $8,230,900 at 1000-mw). This, of course, assumes that only the shipping cost for recycle MgO is charged to the power company (see tables A-81, A-86, A-91 of Appendix A) and, on that basis, makes the magnesia scrubbing process more attractive to the power company than limestone-wet scrubbing. If, as previously assumed, no charge other than shipping cost is made to the chemical company for magnesium sulfite, to earn a profit, the chemical company would only have to get more net sales revenue for the acid than it costs to process the magnesium sulfite into finished product. As predicted in the Marketing section, the sizes, flexibility of operation, and location of centralized acid plants should permit an average net revenue of $12/ton of acid. This value can be compared with the results shown in table 59 of the Investment and Operating Cost section which indicate a magnesium sulfite calcining and acid manufacturing cost range of $15.35-36.52/ton of acid in central process systems. This obviously will not attract any nonregulated companies into the magnesia-regeneration sulfuric acid business. As an added financial incentive, therefore, the chemical company must charge the power company for recycle MgO, but not so much as to result in a scrubbing-drying cost greater than limestone-wet scrubbing or other practical SO_2 abatement measures.

In simpler terms, the power company would finance the stack gas scrubbing-sulfite drying operation for their

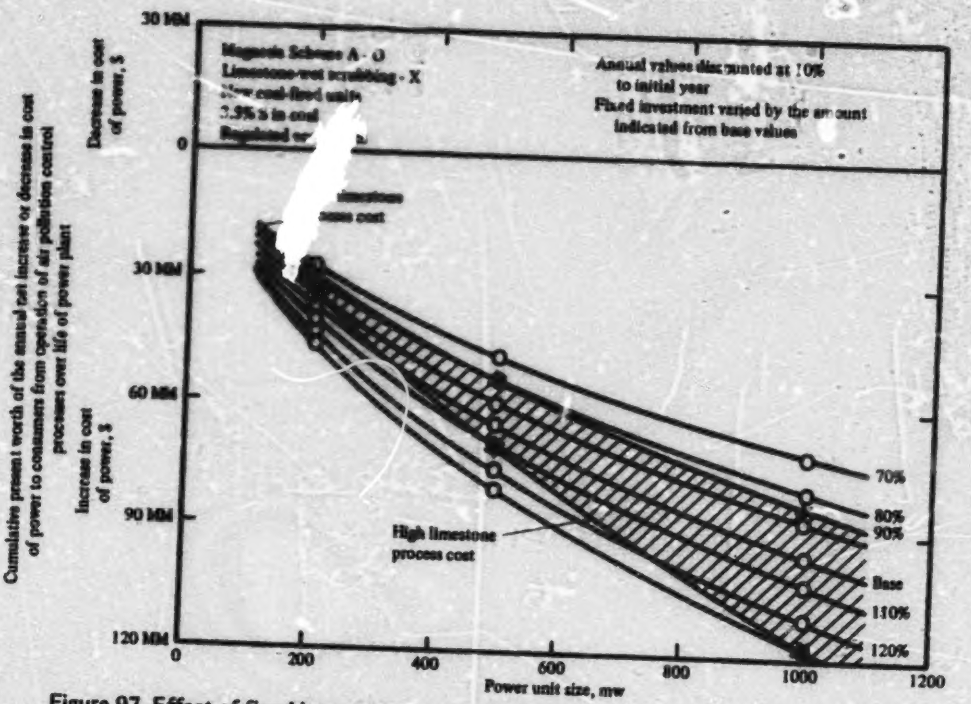

Figure 97. Effect of fixed investment on cumulative present worth of total net increase or decrease in the cost of power to consumers for coal-fired units using magnesia Scheme A.

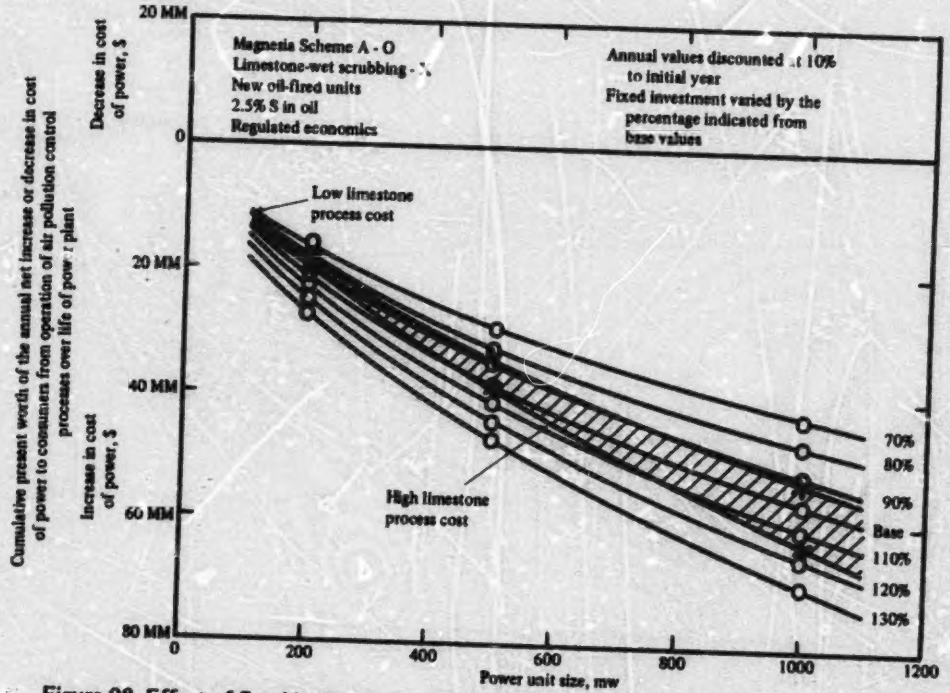

Figure 98. Effect of fixed investment on cumulative present worth of total net increase or decrease in cost of power to consumers for oil-fired units using magnesia Scheme A.

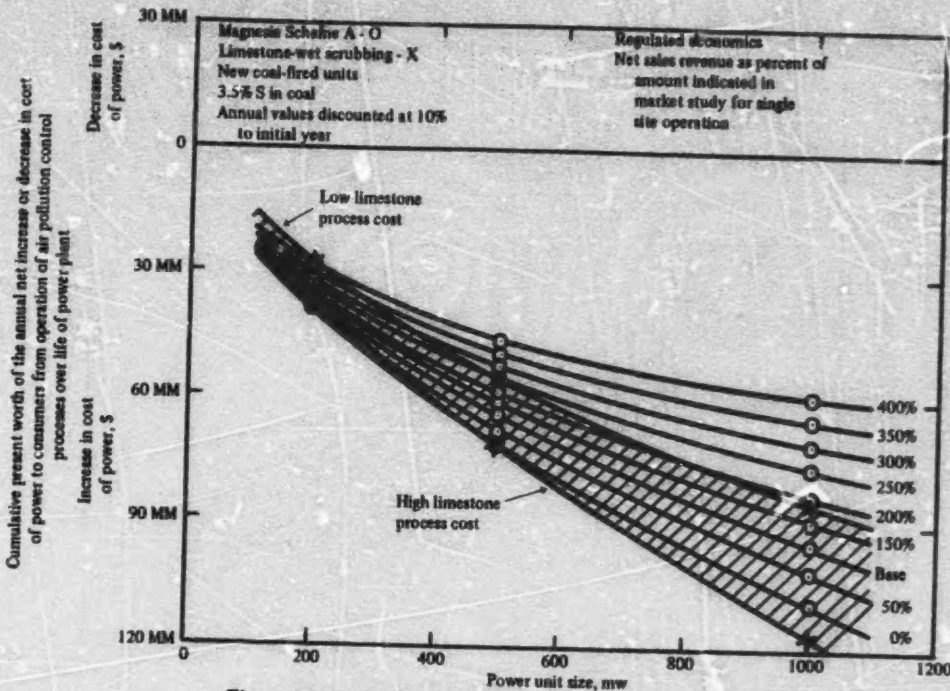

Figure 99. The effect of variation in net sales revenue on cumulative present worth of total net increase or decrease in the cost of power to consumers for coal-fired units using magnesia Scheme A.

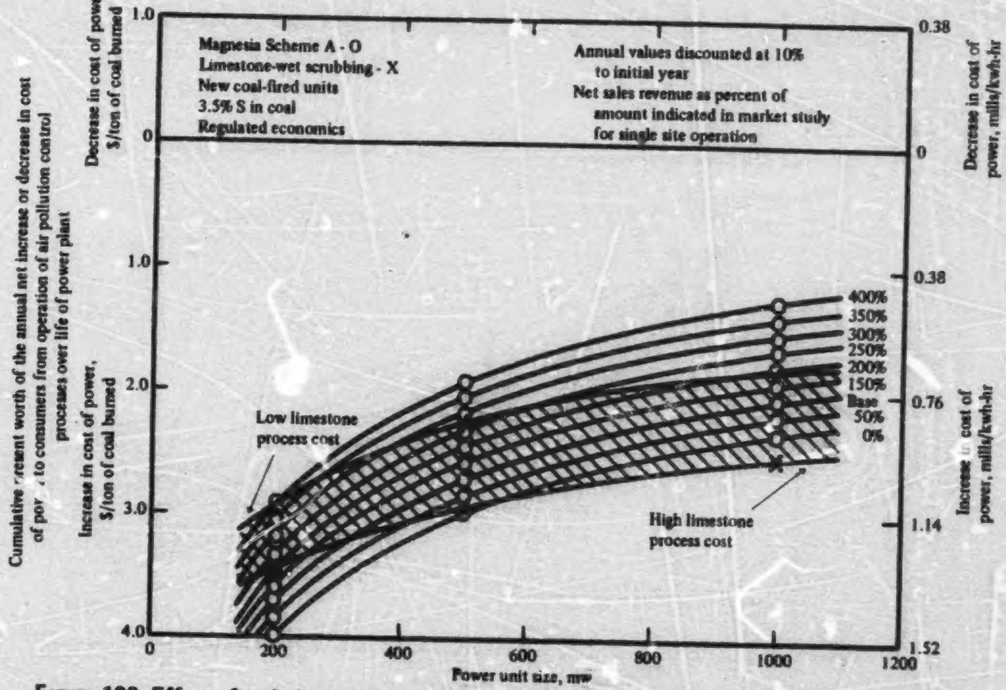

Figure 100. Effect of variation in net sales revenue on cumulative present worth of unit increase or decrease in cost of power to consumers for coal-fired plants using magnesia Scheme A.

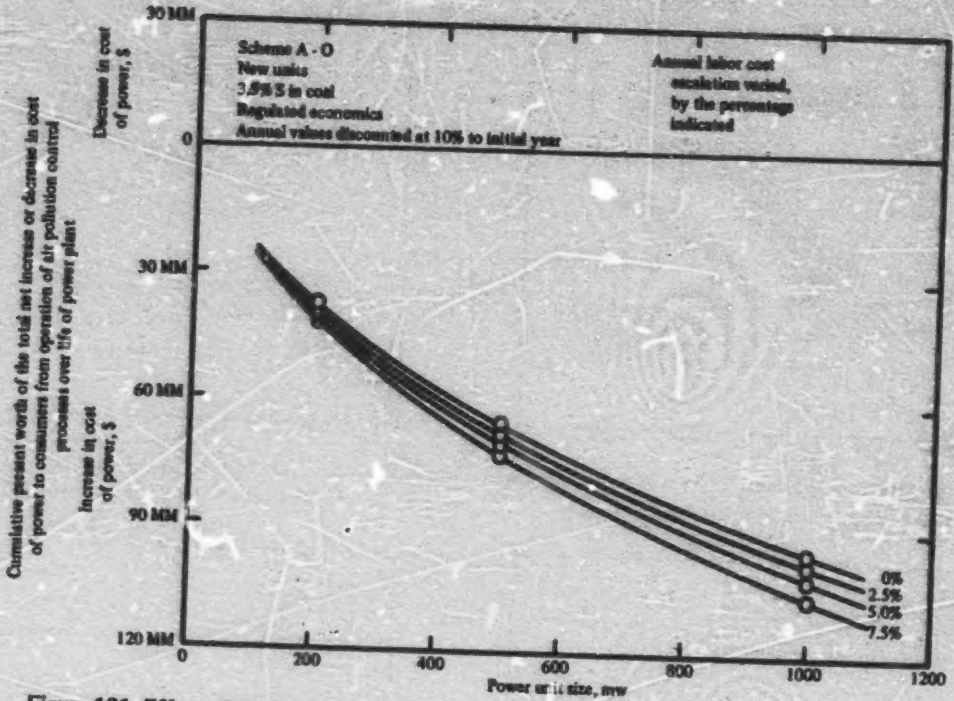

Figure 101. Effect of annual labor cost variation on cumulative present worth of total increase or decrease in cost of power to consumers for coal-fired units using magnesia Scheme A.

generating unit, paying full price for makeup MgO ($102.40/ton Chicago area), plus paying partial price and shipping cost of recycle MgO (approximately $5-65/ton depending on size of operation). In addition, they would "dispose" of their dry, waste magnesium sulfite crystals at no charge other than for shipping to the chemical company (which means no additional cost or space requirements). As long as the power companies are not charged excessively for recycle MgO, they can remove particulates and SO_2 by magnesia wet-scrubbing at a total cost equivalent to or less than the least cost alternate; for comparison, limestone-wet scrubbing is assumed for the alternate. If the price for recycle MgO is sufficient, when coupled with sulfuric acid revenue, a chemical company could justify investment in a sulfuric acid plant with magnesium sulfite as raw material rather than elemental sulfur.

In the evaluation to follow, the operating cost of magnesia scrubbing-drying operations over the power unit life is computed under regulated economics using varying recycle magnesium oxide costs and compared with appropriate high and low limestone-wet scrubbing costs to determine prices for the recycle material. The recycle MgO revenue, coupled with acid sales revenue, permits profitability determination for the central regeneration-acid plant under nonregulated evaluation techniques. For this venture only a 10-year regeneration-acid plant life at 8,000 hrs/yr will be assumed. If the central processing concept is sound, in that several independent power units with varying load factors and operating lives will supply the magnesium sulfite so that the loss of any one or two power units is not critical to operation of the acid plant, then, with power demand growing as projected, the life of the acid plant is independent of the power units involved. As one acid plant wears out, another can be justified to take its place.

As shown in computer printouts of tables A-177, A-178, A-187, A-188, A-197, and A-198 in Appendix A, when acid revenue is $12/ton and MgO shipping distance is less than 50 miles, the prices which could be charged for recycle MgO permitting competitive costs with limestone-wet scrubbing are $25-55/ton for 200-mw scrubbing systems, $15-55/ton for 500-mw scrubbing systems, and $10-55/ton for 1000-mw scrubbing systems. These values can be examined further in figure 126 which describes the effect of recycle MgO cost on the discounted change in cost of power to consumers for the scrubbing-drying (regulated) portion of magnesia Scheme D. Using the same data, figure 127 relates the premium in actual and discounted $/ton of low sulfur coal which would be competitive with 200-mw, 500-mw, and 1000-mw magnesia scrubbing-drying units paying various rates for recycle MgO. Presented in figure 128 is the effect of shipping distance for $50-55/ton

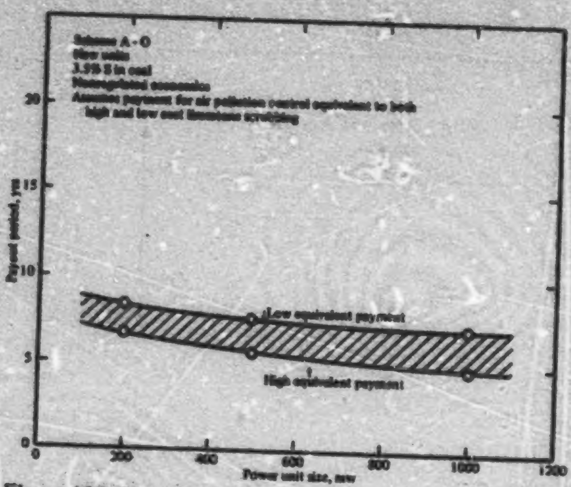

Figure 102. The effect of power unit size on payout period for magnesia Scheme A on coal-fired units.

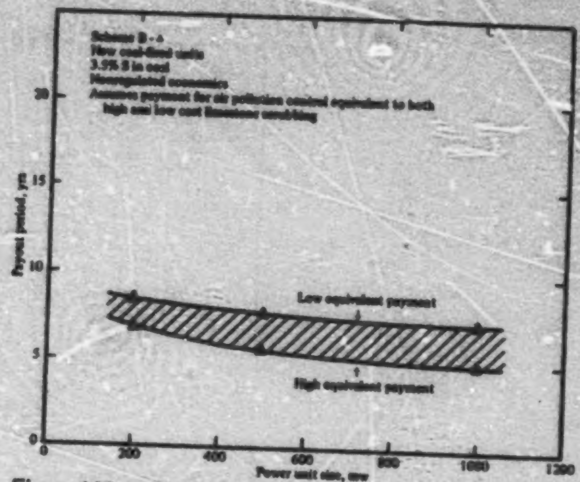

Figure 103. The effect of power unit size on payout period for magnesia Scheme B on coal-fired units.

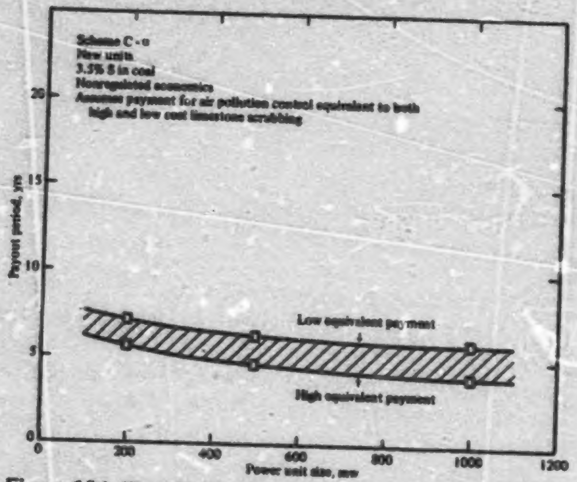

Figure 104. The effect of power unit size on payout period for magnesia Scheme C on coal-fired units.

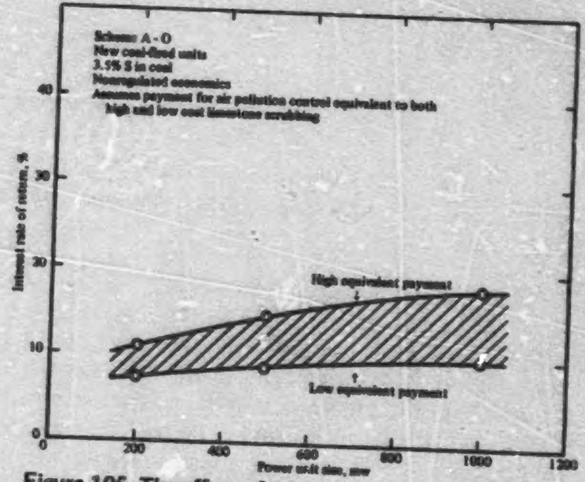

Figure 105. The effect of power unit size on interest rate of return for magnesia Scheme A on coal-fired units.

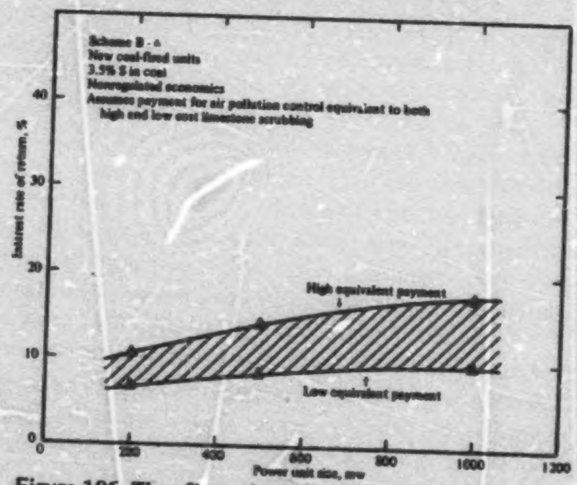

Figure 106. The effect of power unit size on interest rate of return for magnesia Scheme B cn coal-fired units.

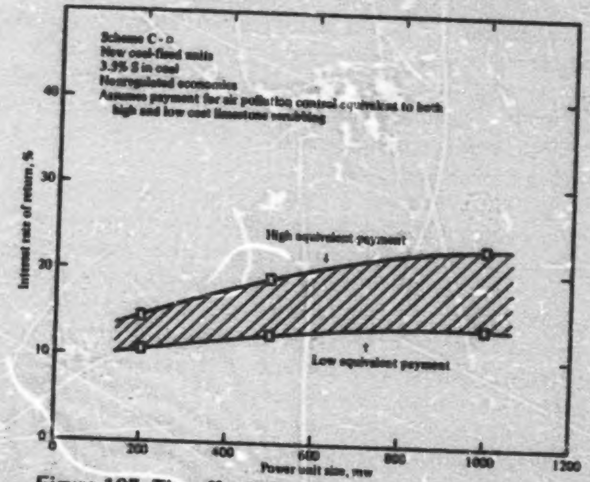

Figure 107. The effect of power unit size on interest rate of return for magnesia Scheme C on coal-fired units.

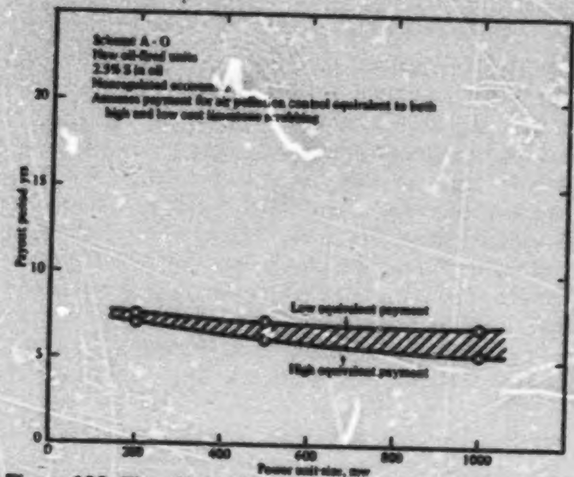

Figure 108. The effect of power unit size on payout period for magnesia Scheme A on oil-fired units.

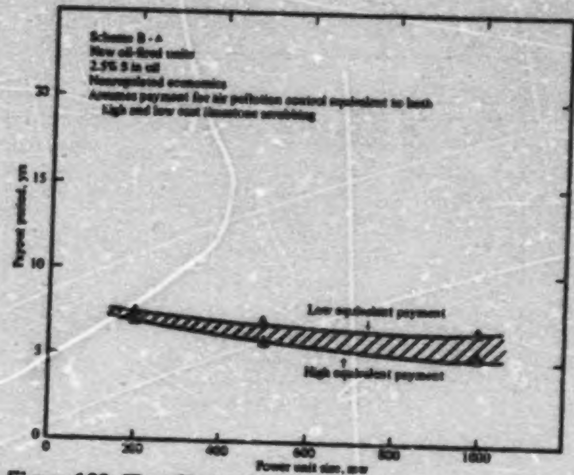

Figure 109. The effect of power unit size on payout period for magnesia Scheme B on oil-fired units.

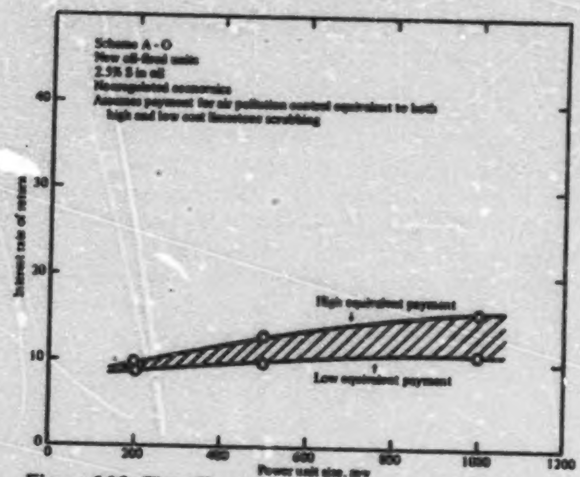

Figure 110. The effect of power unit size on interest rate of return for magnesia Scheme A on oil-fired units.

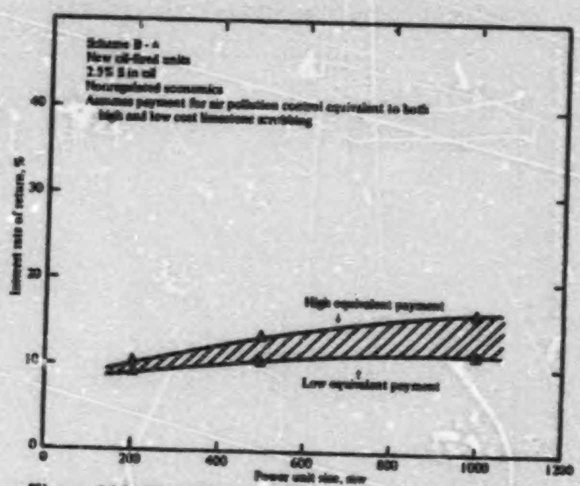

Figure 111. The effect of power unit size on interest rate of return for magnesia Scheme B on oil-fired units.

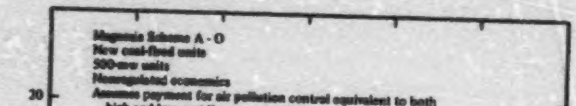

Figure 112. The effect of sulfur content of coal on payout period for magnesia Scheme A on coal-fired units.

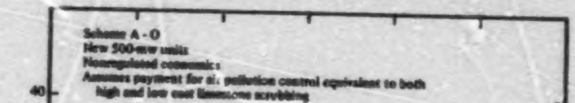

Figure 113. The effect of sulfur content of coal on interest rate of return for magnesia Scheme A on coal-fired units.

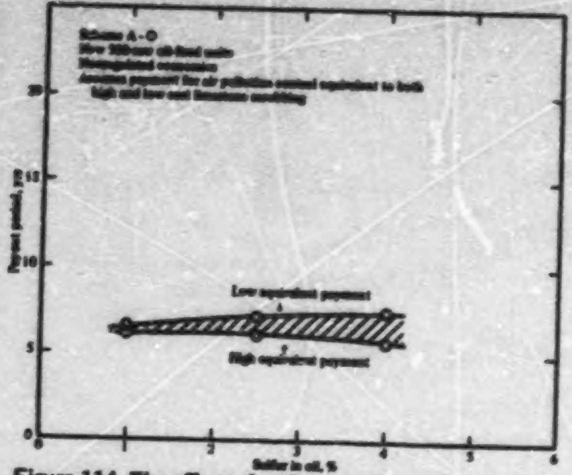

Figure 114. The effect of sulfur content of oil on payout period for magnesia Scheme A on oil-fired units.

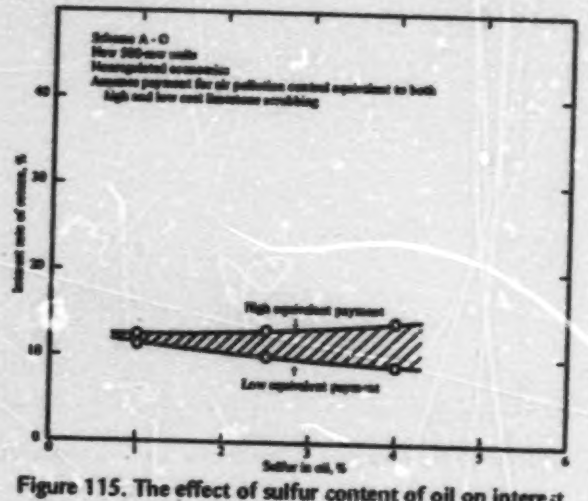

Figure 115. The effect of sulfur content of oil on interest rate of return for magnesia Scheme A on oil-fired units.

recycle MgO on the discounted cost of power to consumers for scrubbing-drying unit sizes of 200-mw, 500-mw, and 1000-mw.

Using the range of recycle MgO prices so developed, the economic potential of central regeneration-acid units can be evaluated for various combinations of 200-mw, 500-mw, and 1000-mw scrubbing-drying systems. Shown in tables 71 and 72 are the expected payout periods and interest rates of return for acid plants with magnesium sulfite feed supplied by scrubbing systems on new power units burning coal with 3.5% sulfur. The results are given for a $12/ton acid net revenue combined with various recycle MgO revenues which equate magnesia scrubbing-drying costs with both low and high cost limestone-wet scrubbing. Detailed calculations are shown in Appendix A tables A-179-186, A-189-196, and A-199-204.

Although the results shown in table 71 indicate, at best, marginal profitability potential, those of table 72, where recycle MgO revenue ranges from $50-55/ton, show excellent economic promise. Two trends are apparent—the larger the central acid plant, the greater the profitability, and the smaller the individual power plant scrubbing-drying systems supplying the $MgSO_3$, the greater the profitability. The reason for this latter relationship is the relatively higher cost of limestone-wet scrubbing on smaller scrubbing units permits a higher price for recycle MgO. In addition, the smaller power units are assumed to be less efficient, requiring more fuel to be burned; hence, more recycle MgO and acid for a given size system. As the results show, 2000-3000-mw (1,333-2,000 tons/day of 100% acid) systems composed of 10-15 small suppliers of sulfite could be very profitable; however, it will be difficult to find, assemble, and coordinate that many systems within a reasonable geographic area.

Presented in figure 129 is the effect of system size on interest rate of return for regeneration-acid units supplied by combinations of 200-mw, 500-mw, and 1000-mw scrubbing-drying units. Also, shown in figures 130 and 131 is the effect of magnesium sulfite shipping distances on interest rate of return covering central unit combinations of 500-mw scrubbing systems with $15/ton and $55/ton recycle MgO revenue. In situations where the magnesia process must compete with low cost limestone scrubbing (rural areas), MgO shipping distance is extremely important.

Figures 132, 133, and 134 describe the effect of variation in net sales revenue for recycle MgO on interest rate of return for the various 200-mw, 500-mw, and 1000-mw combinations of systems. In addition, the effect of variation in sulfuric acid revenue on interest rate of return is described in figures 135 through 140 assuming the required price ranges of recycle MgO for each size system. It can be seen that in situations where high recycle MgO revenue can be obtained, acid revenue is not even required to attain desirable profitability levels with any large centralized regeneration-acid plant. For the lower levels of recycle MgO income, however, acid revenue is extremely important.

Another logical approach to evaluation of the central process concept is to establish a minimum price for recycle MgO consistent with acceptable profitability; then, determine the conditions which would make MgO scrubbing competitive with limestone scrubbing or the premium for low sulfur fuel. For a 2000-mw equivalent acid plant selling acid at $12/ton, MgO recycle price would have to be approximately $20, $27, and $34/ton, respectively, for 10, 15, and 20% after tax rates of return. At the intermediate price level ($27/ton, 15% rate of return), the MgO scrubbing process would be less expensive than low cost

Table 71. Profitability of central regeneration-acid manufacturing unit under cooperative economics.[a] Magnesium sulfite supplied from combinations of new 200-, 500-, or 1,000-mw units burning coal with 3.5% sulfur. Regulated stack gas scrubbing costs equivalent to limestone-wet scrubbing process with low limestone cost, on-site solids disposal.

Case units and size	Payout, years		Interest rate of return, %	
	Recycle MgO at $25/ton	Recycle MgO at $30/ton	Recycle MgO at $25/ton	Recycle MgO at $30/ton
200-mw equivalent	None	None	Neg.	Neg.
5 x 200-mw equivalent	6.6	5.7	8.2	11.6
10 x 200-mw equivalent	5.2	4.5	14.0	17.9
15 x 200-mw equivalent	4.6	4.0	17.2	21.4
	Recycle MgO at $15/ton	Recycle MgO at $20/ton	Recycle MgO at $15/ton	Recycle MgO at $20/ton
500-mw equivalent	None	None	Neg.	Neg.
2 x 500-mw equivalent	9.9	8.1	0.3	4.1
4 x 500-mw equivalent	7.7	6.3	5.1	9.5
6 x 500-mw equivalent	6.5	5.4	8.7	13.2
	Recycle MgO at $10/ton	Recycle MgO at $15/ton	Recycle MgO at $10/ton	Recycle MgO at $15/ton
1,000-mw equivalent	None	None	Neg.	Neg.
2 x 1,000-mw equivalent	9.9	7.8	0.1	4.8
3 x 1,000-mw equivalent	8.3	6.6	3.5	8.4

[a] Nonregulated portion of system with 10 yr life; acid revenue–$12/ton.

Table 72. Profitability of central regeneration-acid manufacturing unit under cooperative economics.[a] Magnesium sulfite supplied from combinations of new 200-, 500- or 1,000-mw units burning coal with 3.5% sulfur. Regulated stack gas scrubbing costs equivalent to limestone-wet scrubbing process with high limestone cost, off-site solids disposal.

Case units and size	Payout, years		Interest rate of return, %	
	Recycle MgO at $50/ton	Recycle MgO at $55/ton	Recycle Mgo at $50/ton	Recycle MgO at $55/ton
200-mw equivalent	9.3	8.4	1.3	3.3
5 x 200-mw equivalent	3.7	3.4	23.8	26.6
10 x 200-mw equivalent	2.9	2.7	32.2	35.5
15 x 200-mw equivalent	2.6	2.4	36.9	40.6
	Recycle MgO at $50/ton	Recycle MgO at $55/ton	Recycle MgO at $50/ton	Recycle MgO at $55/ton
500-mw equivalent	5.6	5.1	12.1	14.4
2 x 500-mw equivalent	3.8	3.5	22.6	25.3
4 x 500-mw equivalent	3.0	2.8	30.9	34.1
6 x 500-mw equivalent	2.6	2.4	36.2	39.7
	Recycle MgO at $50/ton	Recycle MgO at $55/ton	Recycle MgO at $50/ton	Recycle MgO at $55/ton
1,000-mw equivalent	3.9	3.6	21.8	24.4
2 x 1,000-mw equivalent	3.1	2.9	29.9	33.0
3 x 1,000-mw equivalent	2.7	2.5	35.1	38.5

[a] Nonregulated portion of system with 10 yr life: acid revenue–$12/ton.

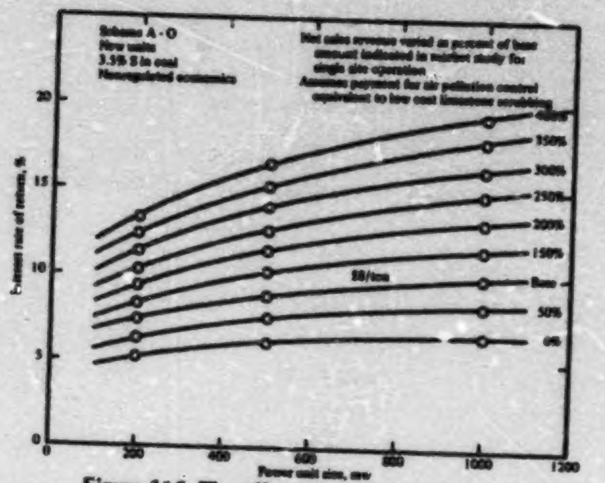

Figure 116. The effect of variation in net sales revenue on interest rate of return for magnesia Scheme A on coal-fired units—low payment.

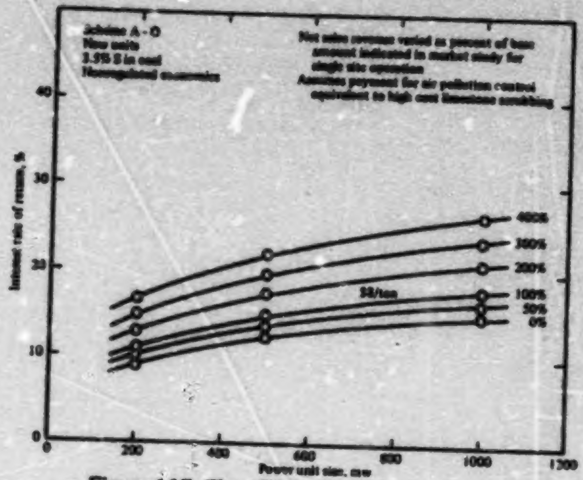

Figure 117. The effect of variation in net sales revenue on interest rate of return for magnesia Scheme A on coal-fired units—high payment.

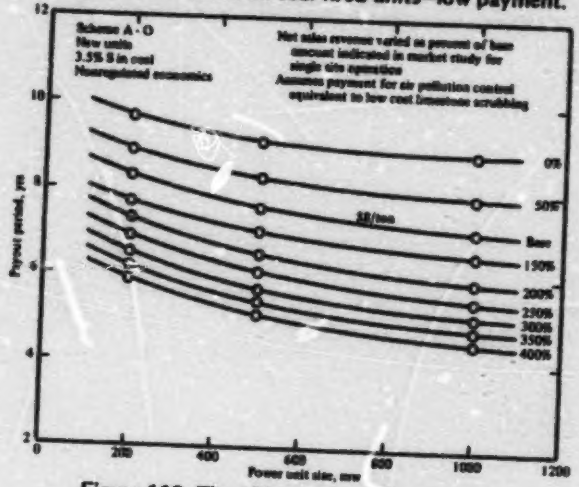

Figure 118. The effect of variation in net sales revenue on payout period for magnesia Scheme A on coal-fired units—low payment.

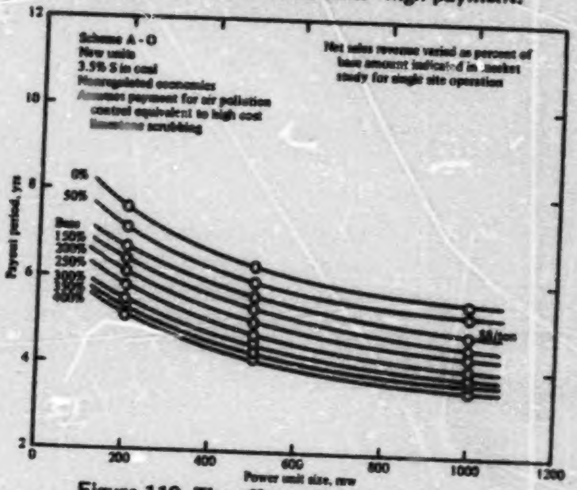

Figure 119. The effect of variation in net sales revenue on payout period for magnesia Scheme A on coal-fired units—high payment.

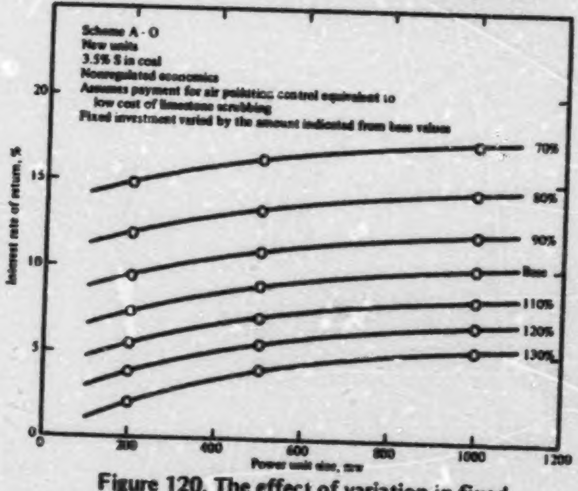

Figure 120. The effect of variation in fixed investment on interest rate of return for magnesia Scheme A on coal-fired units—low payment.

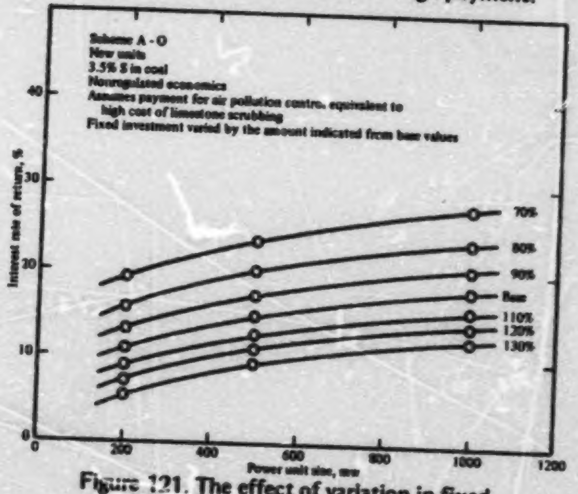

Figure 121. The effect of variation in fixed investment on interest rate of return for magnesia Scheme A on coal-fired units—high payment.

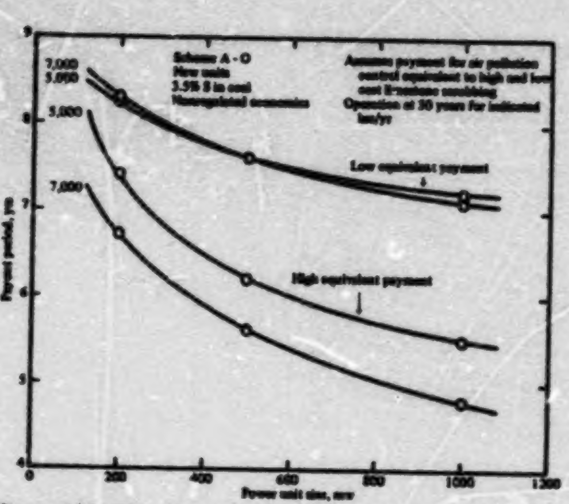

Figure 122. The effect of constant onstream time on payout period for magnesia Scheme A on coal-fired units.

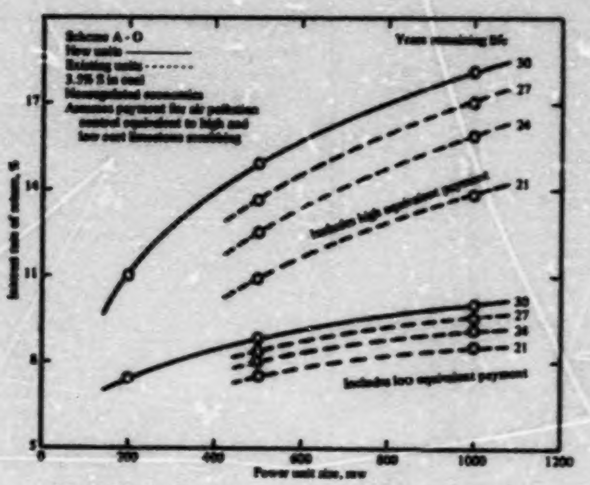

Figure 123. The effect of power unit age or status on interest rate for magnesia Scheme A on coal-fired units.

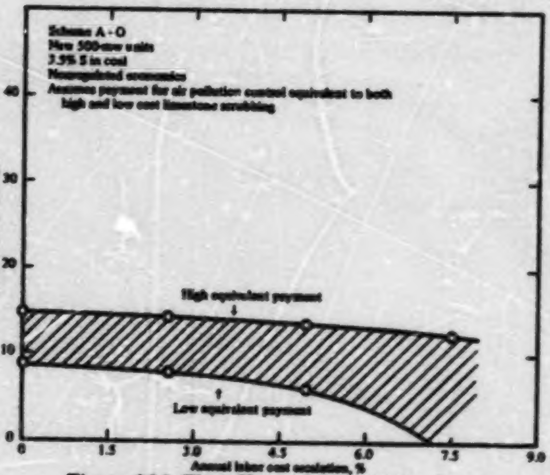

Figure 124. The effect of annual labor cost escalation on interest rate of return for magnesia Scheme A on coal-fired units.

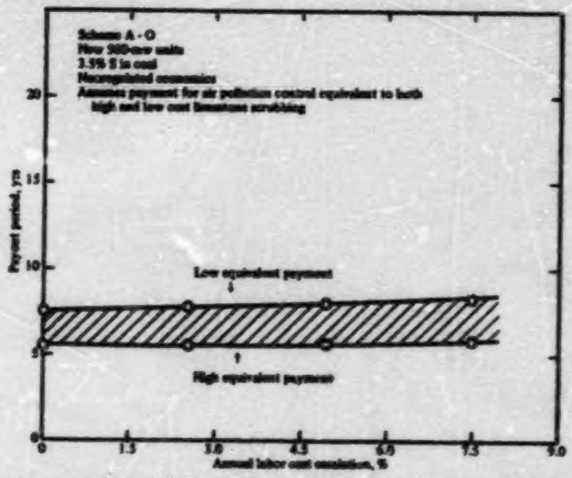

Figure 125. The effect of annual labor escalation on payout period for magnesia Scheme A on coal-fired units.

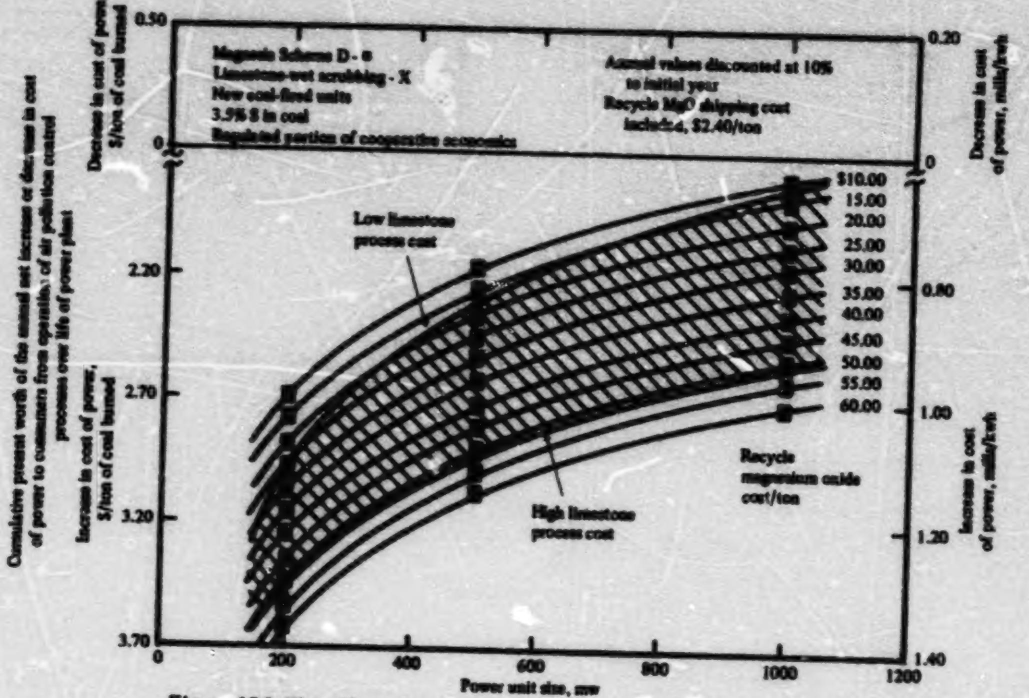

Figure 126. The effect of recycle magnesium oxide cost on cumulative present worth of increase or decrease in cost of power to consumers for regulated portion of magnesia Scheme D under cooperative economics.

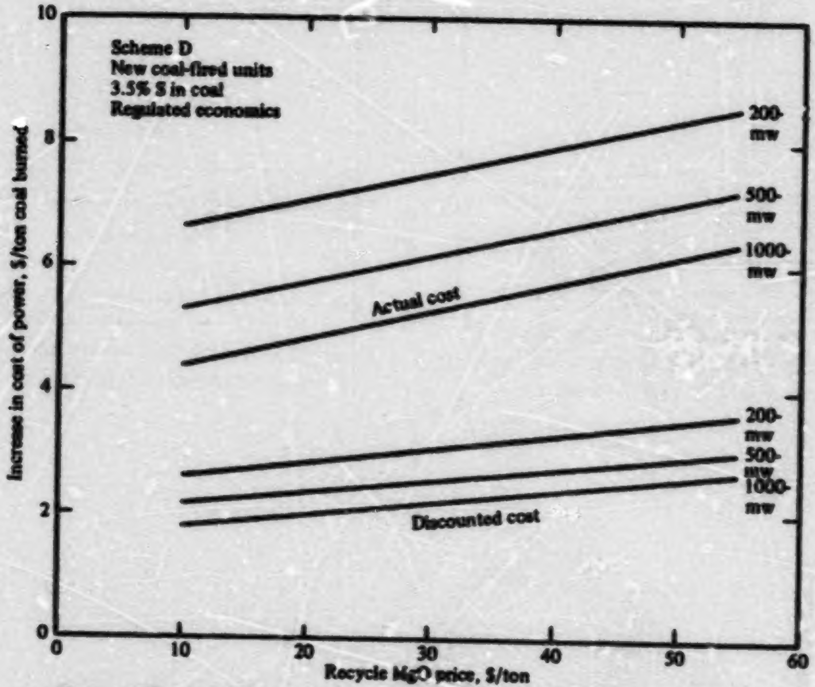

Figure 127. The relationship of recycle MgO cost on increase in the cost of power to consumers for 200-, 500-, and 1000-mw scrubbing systems of Scheme D.

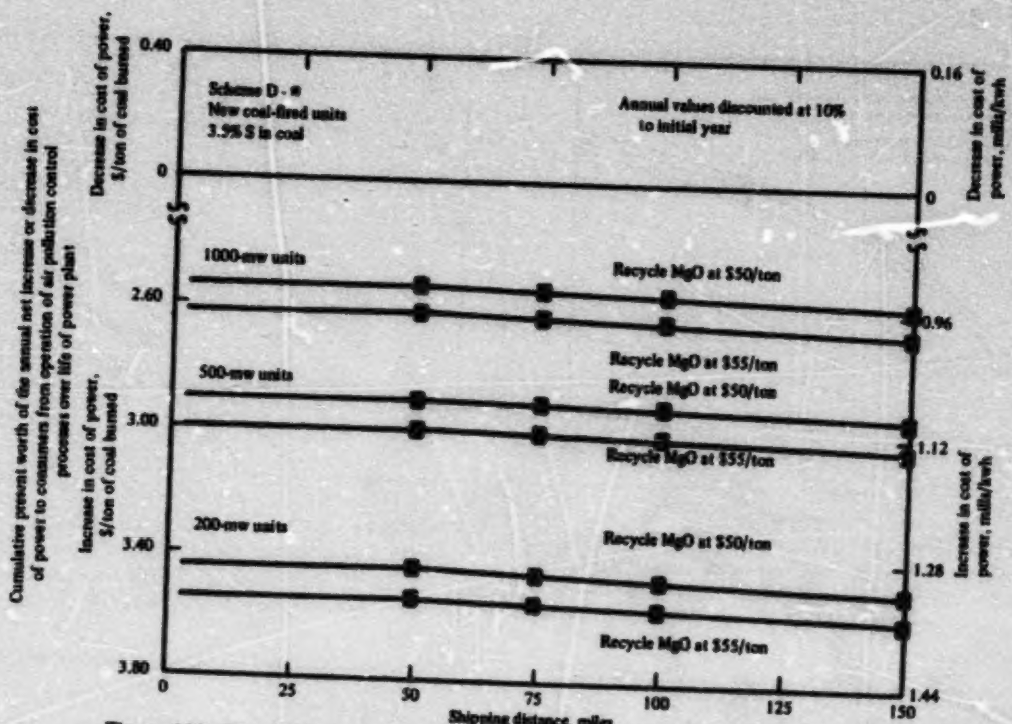

Figure 128. The effect of shipping distance for recycle magnesium oxide on cumulative present worth of the increase or decrease in unit cost of power to consumers in the regulated portion of magnesia Scheme D under cooperative economics.

limestone scrubbing for power units 200-mw and smaller (see figure 126) up to 50 miles from the central plant location. For 500-mw power units located 50 miles from the central processing plant, the price of recycle MgO would have to be approximately $18/ton to be competitive with low cost limestone scrubbing and this would result in an 8% interest rate of return to the chemical company. If a high cost limestone process is the competition (permitting $55/ton for recycle MgO), even a single 500-mw equivalent regeneration-acid plant could be justified.

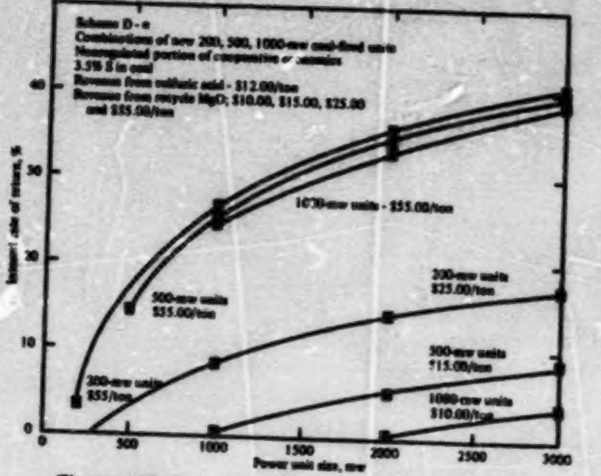

Figure 129. The effect of power unit size on interest rate of return of centralized regeneration-acid plants supplied by combinations of 200-, 500-, and 1000-mw scrubbing systems under cooperative economics.

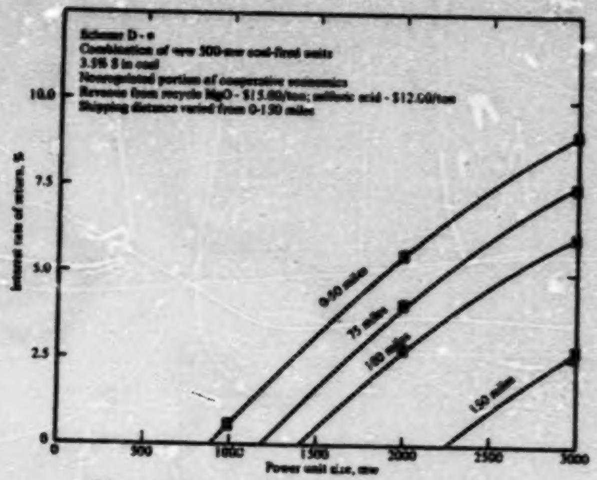

Figure 130. The effect of shipping distance on interest rate of return for centralized regeneration-acid units–combinations of 500-mw scrubbing systems, recycle MgO cost–$15/ton.

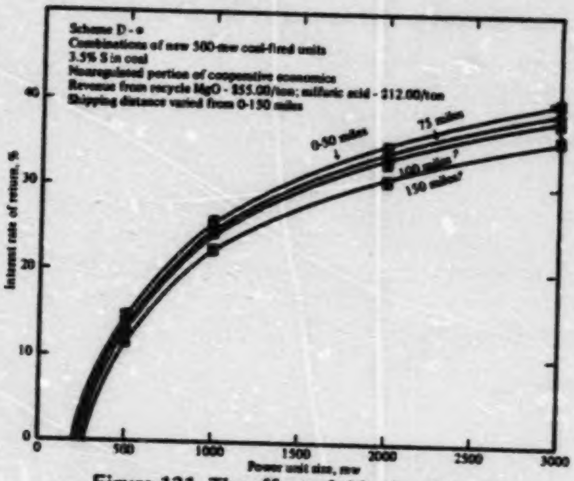

Figure 131. The effect of shipping distance on interest rate of return for centralized regeneration-acid units–combinations of 500-mw scrubbing systems, recycle MgO cost–$55/ton.

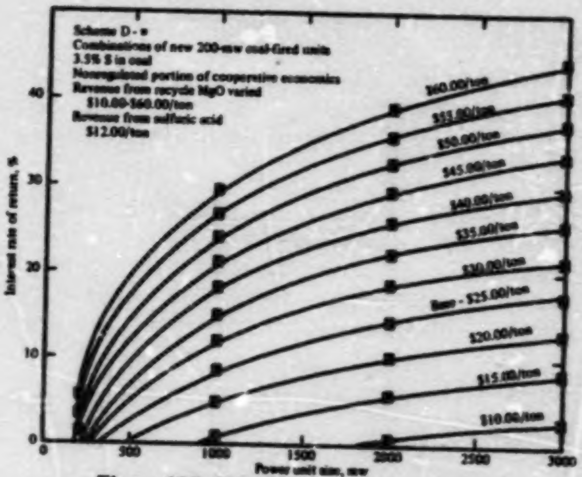

Figure 132. The effect of variation in sales revenue for recycle MgO on interest rate of return of centralized regeneration-acid units–combinations of 200-mw scrubbing systems.

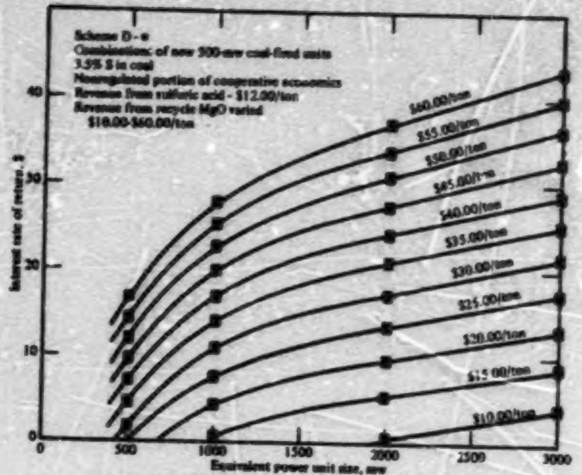

Figure 133. The effect of variation in sales revenue for recycle MgO on interest rate of return of centralized regeneration-acid units—combinations of 500-mw scrubbing systems.

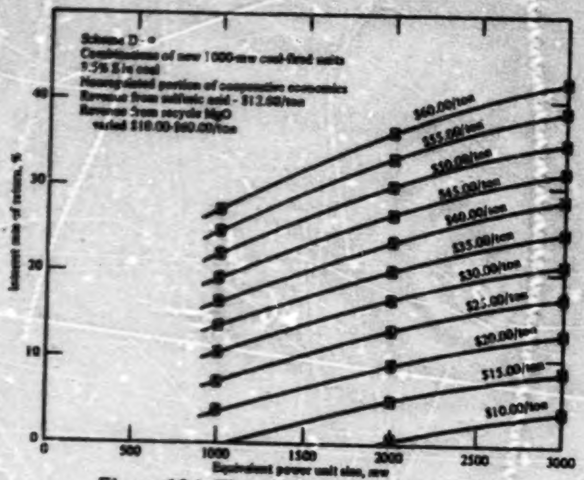

Figure 134. The effect of variation in sales revenue for recycle MgO on interest rate of return for centralized regeneration-acid plants—combinations of 1000-mw scrubbing systems.

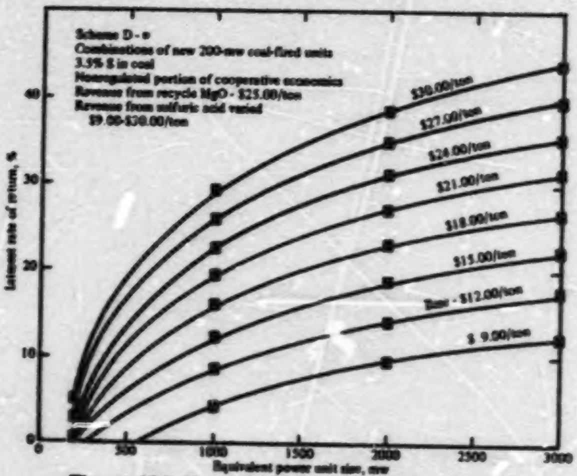

Figure 135. The effect of variation in net sales revenue for sulfuric acid on interest rate of return for centralized regeneration-acid units—combinations of 200-mw scrubbing systems—recycle MgO cost—$25/ton.

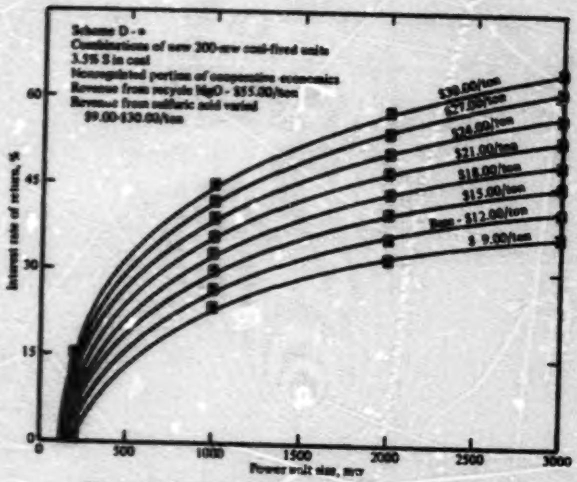

Figure 136. The effect of variation in net sales revenue for sulfuric acid on interest rate of return for centralized regeneration-acid units—combinations of 200-mw scrubbing systems—recycle MgO cost—$55/ton.

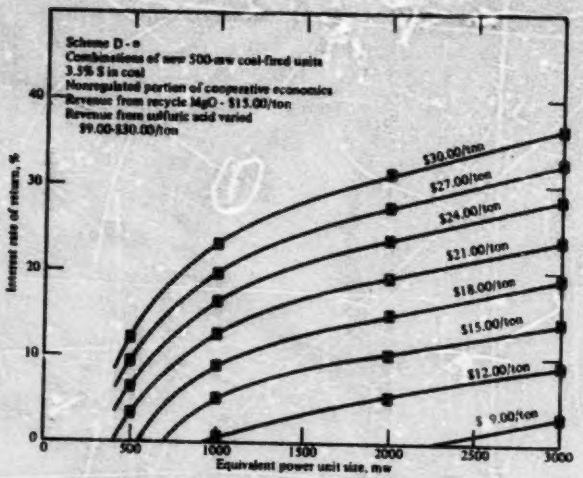

Figure 137. The effect of variation in net sales revenue for sulfuric acid on interest rate of return for centralized regeneration-acid units–combinations of 500-mw scrubbing systems–recycle MgO cost–$15/ton.

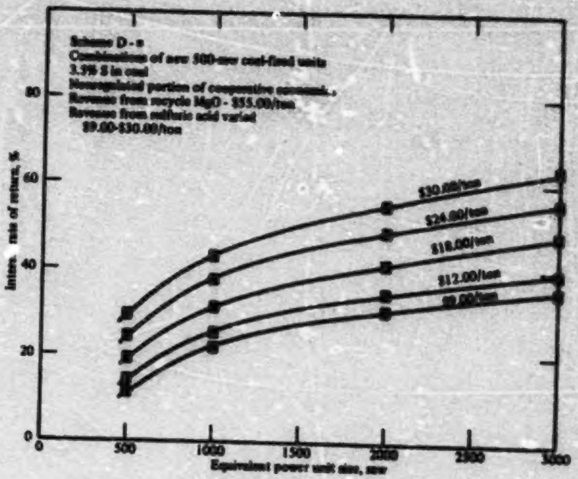

Figure 138. The effect of variation in net sales revenue for sulfuric acid on interest rate of return for centralized regeneration-acid units–combinations of 500-mw scrubbing systems–recycle MgO cost–$55/ton.

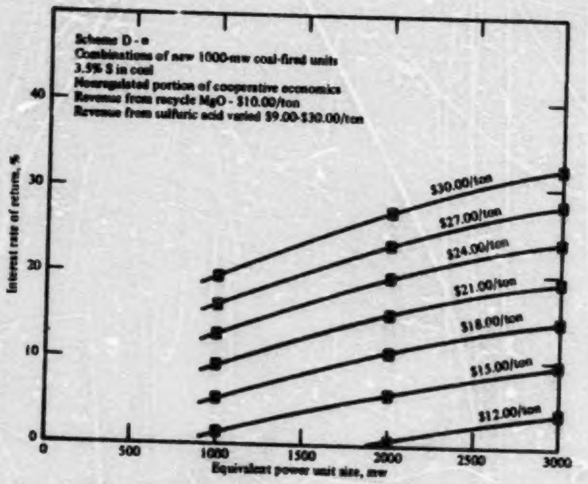

Figure 139. The effect of variation in net sales revenue for sulfuric acid on interest rate of return for centralized regeneration-acid units–combinations of 1000-mw scrubbing systems–recycle MgO cost–$10/ton.

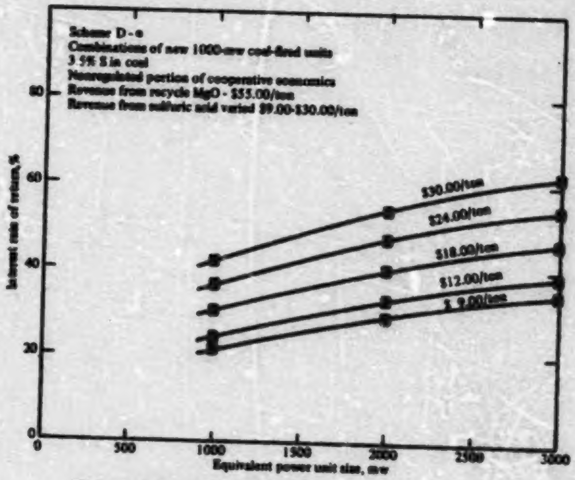

Figure 140. The effect of variation in net sales revenue for sulfuric acid on interest rate of return for centralized regeneration-acid units–combinations of 1000-mw scrubbing systems–recycle MgO cost–$55/ton.

RESEARCH AND DEVELOPMENT NEEDED

Of the four processes evaluated under the EPA-TVA conceptual design and cost series, the magnesia process development was probably the most advanced at the time the study was initiated. As mentioned earlier, a 155-mw demonstration system utilizing the magnesia slurry process (Scheme A) has been built and was started up in early 1972 on an oil-fired Boston Edison power unit. A number of items needing further research and development are being studied in the demonstration scale system.

Further development work needed can be classified into three categories: process phases, equipment performance, and system operation. Although it is desirable to have additional information such as physical properties, mass transfer rates, absorber efficiencies and pilot plant operating data, the emphasis should be centered on process confirmation and improvement, equipment performance and reliability, and system compatibility with power plant operation.

There are several process phases worthy of additional attention, including use of unrefined magnesia as raw material, formation of magnesium sulfite trihydrate crystals in scrubbing slurry, contamination buildup and removal, crystal growth and scaling, oxidation in the scrubber and dryer, clear liquor scrubbing and sulfite precipitation, and the manufacture of sulfur in the calciner. With the exception of scaling and contamination, which can interfere with process operation, most of these areas of study are process modifications to extend usefulness and to improve economics.

The least expensive forms of magnesium oxide are dolomite and raw magnesia. If process contamination tolerances can be defined, some raw material savings might be achieved by using these materials.

Potential problems associated with buildup of contaminants from recycle of process raw material have been given some attention in this report; however, very little data exists to define the actual compounds, their rate of buildup, and their effect on the process. Data of this type can only be obtained over a long period of process operation with remedial measures taken after definition. It may well be that contaminants and the level of buildup will vary from operation to operation depending on fuel characteristics, source of makeup MgO, and process water composition. Although the flow diagram for each scheme shows a point where a decontamination purge should be taken, actual results may indicate otherwise.

Some investigators have indicated that magnesium sulfite trihydrate rather than hexahydrate crystals may be formed in the scrubbing loop at scrubbing temperatures normally encountered (125-135° F). Research data available does not generally confirm this; however, the data is not all inclusive, and some doubt remains, especially with actual slurries as opposed to simulated slurries. Considerable heat savings could be derived if easily separatable trihydrate crystals could be formed directly in the scrubbing slurry. Even using induced thermal conversion of the hexahydrate crystals to form trihydrate material, as suggested in this report, may not be acceptable if the smaller trihydrate crystals (1:10) can not be dewatered easily. Additional data from pilot plant or demonstration-scale operation is desirable to clarify this procedure.

Oxidation of sulfite to sulfate in the scrubbing and drying operations requires increased use of reducing coke or higher temperatures in the calciner. As discussed in the Process Chemistry, Properties and Kinetics section, various organic compounds can be used to retard oxidation in the scrubber; however, they probably would be consumed or decomposed in the drying-calcination steps and would need to be replaced. Since these organics are generally expensive, their value as an oxidation retardant would have to be compared to their replacement expense. Data is needed both on their effectiveness as retardants and their expected losses per cycle. In addition to oxidation in the scrubber loop, information on sulfite oxidation in the dryer under various combustion conditions and in storage over a period of time may be worthwhile.

Chemico-Basic has carried out some development with clear liquor scrubbing, Scheme C, with less than desirable SO_2 removal; however, these results were limited. As can be seen in the economic evaluation, Scheme C has the least investment and operating costs of the schemes studied, and on that basis, appears worthy of additional development work. Perhaps minor pH changes to the 6.0-6.5 range or increased L/G would permit improved SO_2 removal with a totally soluble sulfite-bisulfite liquor.

One of the most important process phases requiring additional study is crystal size and growth. Crystal characteristics are important in the scrubber system for $MgSO_3$ formation and scale prevention, in the dewatering step for liquids-solids separation, and in the dryer for agglomeration. Figures 12, 13, and 14 in the Process Chemistry, Properties and Kinetics section are photomicrographs of synthetically prepared sulfite tri- and hexahydrate crystals and are helpful in studying crystal habit. It appears desirable to form crystals as large as possible to promote sulfite precipitation without scaling and liquid-solid separation. Although not confirmed, larger crystals also may reduce erosion in the system.

In connection with crystal growth and scaling is a process variable needing additional study, solids concentration in the scrubbing slurry. Results at TVA in limestone slurry scrubbing indicate a relationship between slurry solids concentration, and scaling and erosion of unprotected surfaces. With greater solids concentration, less scaling is encountered, but more erosion is usually experienced. From a liquid-solid separation viewpoint, it is desirable to feed the highest possible solids concentration to the thickener, screen, and centrifuge. Although preliminary tests have been made, their results have not provided conclusive data.

Speculation has been raised as to possible direct manufacture of sulfur in the calcination step by alteration of calciner design and/or operating conditions. As discussed in the Process Chemistry, Properties and Kinetics section, some small-scale work has been done in the area; however, application to commercial systems remains suspect. Such a concept, if development were successful, could result in investment cost savings and a more desirable end product.

Areas of additional equipment development include spray scrubbing, corrosion and erosion protection, mist elimination in slurry service, and fluid bed drying and calcination. The Grillo work with high gas velocities in concurrent spray scrubbers indicates potential scrubber cost savings for MgO-MnO_2 slurries (Scheme B). It is conceivable that additional development in spray scrubbing technology could lead to application in the magnesia slurry and clear liquor schemes (A, C, D) where sulfite oxidation is less than for MgO-MnO_2 scrubbing. Recent test work at TVA using limestone slurries in spray scrubbing has been promising; however, mist elimination at high gas velocities and plugging of the eliminators were major problems. This area of research might best be relegated to equipment vendors; however, there is considerable opportunity for joint process and equipment development.

In aqueous scrubbing processes, TVA pilot plant testing has shown mist elimination to be a difficult and expensive operation, especially in slurry service. High elimination efficiency to prevent reentrainment of scrubbing salts and lower reheat requirements, plus the prevention of plugging in separation devices, are essential for large-scale application of aqueous scrubbing systems. Much equipment development effort is needed in this area.

Fluid bed dryers and calciners are used in the schemes presented in this report; however, very little magnesia process test work has been performed using these devices. Initial development, including the Boston Edison demonstration plant, utilizes the less efficient, but dependable, rotary dryer and calciner. Fluid bed equipment vendors feel that their devices should work well in these services, and available cost estimates justify considerable effort in this direction. Due to previous successes in the sulfite pulping industry, process developers think it is only a matter of time until fluid bed systems are used for magnesium sulfite drying and magnesia regeneration to obtain the potential cost savings and achieve a more uniform product. If direct sulfur production is to be accomplished, it probably will be with fluid bed systems.

With potential problems such as corrosion, erosion, scaling, and start and stop operation, considerable work will be required to obtain satisfactory coupling of the magnesia process to a power plant. In some cases when aqueous stack gas scrubbing processes have been tested on power units, difficulty has been encountered in obtaining long term, continuous operation. Limited success has been obtained in a few cases, but only after alterations and modifications were made. The Boston Edison demonstration systems should indicate which process alterations and modifications are required for the magnesia process. Questionable areas for specific problems include the reliability of gas by-pass dampers if used, corrosion-erosion resistant materials and linings in scrubber loop, gas and liquid channeling in scrubber units, mist elimination and reheat systems, process materials storage requirements, the need for spare equipment, and location or type of instrumentation required to quickly obtain consistent, even operation under frequent changes in power unit load.

In absence of definitive corrosion and erosion data for the magnesia scrubbing operations, considerable materials testing is recommended for future development. Limited tests under static simulation are almost worthless and data under sustained, dynamic operation conditions are desirable. Knowing the effects of frequent starts and stops, adverse process upsets and length of operation should be very helpful to the design engineers.

CONCLUSIONS AND RECOMMENDATIONS

In reviewing processes for sulfur dioxide removal from power plant stack gas, thus far, no single process studied has exhibited outstanding superiority over all others. Each process has shown some advantages and disadvantages when subjected to a thorough appraisal. In this respect, the magnesia scrubbing-regeneration process is no different; however, it is apparent that the technology of the concept is well founded and its development has advanced considerably during the past few years.

Aqueous scrubbing processes such as the magnesia system have advantages over dry absorption including:

1. Better mass transfer.
2. Easier absorbent handling and circulation.
3. No physcial deterioration of the absorbent.

At the same time, disadvantages such as:

1. Necessity for stack gas reheat.
2. Increased corrosion.
3. Potential to form scale deposits in the scrubbing system.
4. The need to remove water for regeneration of absorbent.

In comparison with other aqueous scrubbing processes, the advantages and disadvantages of the magnesia concept depend on the process with which it is compared. For instance, at a given liquor to gas flow ratio, the mass transfer rate of sulfur dioxide in the stack gas to the aqueous magnesia absorbent is superior to limestone scrubbing, but less than that of the more soluble sodium, potassium, and ammonium compounds. The corrosion-erosion rates and potential to form scale deposits of magnesia slurry scrubbing are less than limestone slurries, but possibly greater than the soluble alkali salts. Reheat, entrainment, and absorbent loss problems are nearly the same for all aqueous scrubbing schemes.

Unlike the nonrecovery limestone processes studied earlier in the EPA-TVA series, the magnesia scrubbing process recovers the SO_2 in the stack gas as a salable, commercial product. Either concentrated (98%) sulfuric acid, liquified sulfur dioxide, or elemental sulfur could be produced for sale.

The most attractive assets of the magnesia concept are:

1. The ease of separation of the sulfite salt from the scrubber liquor.
2. The ability to regenerate and recycle the absorbent, magnesium oxide.
3. The avoidance of a solids disposal problem.
4. The possibility of setting up a centralized regeneration-acid unit separating both financially and operationally the power unit-scrubbing system from the commercial, chemical product function.

It is the last two advantages that have captured the interest of the decision-making officials in the power industry; the ability to remove SO_2 from the stack gas and dispose of it off-site, remaining free of any chemical marketing liability.

The process does have notable requirements such as:

1. The need for two scrubbing stages when using slurry on coal-fired units to avoid mixing the fly ash with undissolved magnesium.
2. Relatively high energy usage to generate more concentrated SO_2.
3. The necessity to market the product(s) with limited flexibility in demand.

Probably, the greatest obstacle to immediate, wide application is the current market price for sulfur which permits less expensive manufacture of sulfuric acid by conventional routes as compared to the calcination of magnesium sulfite, even if the sulfite could be obtained free of charge.

Advanced development has been carried forth on three technological variations of the magnesia process. Pilot plant runs have been made on the critical portions of the following sulfur dioxide removal schemes:

Scheme A–Slurry scrubbing with partially dissolved magnesium oxide-magnesium sulfite at a basic pH, separation and drying of the predominantly sulfite crystals, regeneration to MgO, and concentrated (16%) sulfur dioxide.

Scheme B–Slurry scrubbing with partially dissolved magnesium oxide-magnesium sulfite-manganese dioxide, separation and drying of the solids, and regeneration to MgO, MnO_2, and concentrated (13%) SO_2.

Scheme C–Solution scrubbing with dissolved magnesium sulfites at an acidic pH, precipitation of sulfite by addition of MgO, and separation and drying of resultant crystals with regeneration to MgO and concentrated (16%) SO_2.

Although all three variations appear feasible, only the basic slurry scrubbing schemes (A and B) are capable of 90% plus sulfur dioxide removal from power plant stack gas (less than 4,000 ppm, SO_2). The high vapor pressure of SO_2 over the solution of sulfites makes it difficult to obtain efficiencies greater than 80-85% with Scheme C. Because of the greater SO_2 removal, the slurry variations have received more attention during recent years. As previously stated, there is a need for some additional pilot plant studies of various process phases; however, the slurry concepts are definitely ready for larger scale demonstration.

Recently, some research has been carried out on NO_x removal by magnesia scrubbing and the manufacture of sulfur directly in the calciner offgas. Based on preliminary results reported by Babcock and Wilcox (26), the magnesia process does not appear to be effective for NO_x removal (10% or less) and, therefore, should not be depended on as a means of NO_x control. For the direct manufacture of sulfur, little applied research has been reported, but theoretical evaluation indicates some merit for additional work. At the present value of elemental sulfur, however, the additional cost required to produce sulfur rather than acid may not be justified (11).

Full scale equipment which would permit at least limited operation of the magnesia scrubbing-regeneration process could be purchased today. Several scrubber designs are available including venturi, mobile bed, and spray types for slurries and, in addition to these, packed and tray types for solutions. Performance and reliability data for full scale equipment is not yet available; however, within limits, fabricators could provide workable devices. Although the Boston Edison, 155-mw demonstration is the first large scale application of the magnesia process, many of the items such as centrifuges, screens, pumps, conveyors, and tanks require no special design other than specification of materials of construction. Sulfuric acid plant designers could easily provide systems to produce acid from calciner offgas.

One major area of equipment design needing further attention is in fluid bed drying and calcination. The 155-mw demonstration system uses rotary equipment; however, future installations may be fluid bed types. There are companies who feel they can adapt current fluid bed designs without major alterations.

At this time, mist eliminator design is of concern; however, development of efficient, reliable devices should be forthcoming as soon as experience is obtained in large stack gas wet-scrubbing applications. More than likely, entrainment separators for magnesia scrubbing will be very similar to devices used for other wet scrubbing processes.

The unit investment requirements for magnesia scrubbing-regeneration vary over a wide range—\$14.9/kw for a new, 1000-mw, 1.0% S in fuel, oil-fired power system to \$65.4/kw for an existing, 200-mw, 3.5% S in fuel, coal-fired system. Comparable limestone-wet scrubbing figures are \$14.8/kw to \$51.5/kw; however, no product is produced and a large solids disposal problem must be endured. In 1969-70, investment for the three ammonia scrubbing-fertilizer manufacturing processes evaluated under the EFA-TVA series (87) ranged from \$24.6/kw for a new, 1000-mw system to \$62.6/kw for a 200-mw, existing system; however, these values are not up-to-date and the processes evaluated manufactured finished, consumer products (28-14-0, 26-19-0, and 20-15-0 N.P.K. fertilizers).

For coal-fired units, the investment requirements for magnesia Scheme C are lowest of the three technological variations studied and those of Scheme B, only marginally the highest. The use of a single scrubber to remove both fly ash and sulfur dioxide is the primary reason for reduced cost of Scheme C; however, the reduced throughput of material due to lower SO_2 removal also has some effect. The Scheme B scrubber cost is less than Scheme A because of the improved mass transfer using MnO_2 in the slurry; however, this cost improvement is offset by the quantity of material which must be dried and handled. Impurities and MnO_2 from pyrolusite, the purchased form of manganese dioxide, are a noticeable burden even though the MnO_2 improves mass transfer in the scrubber, and permits calcination of sulfite-sulfate without coke at only slightly higher temperature. Again, for oil-fired units (Scheme C not applicable), Scheme A investment is slightly less than Scheme B. As expected, process investment for oil-fired units is much less than for coal-fired systems.

The investment for magnesia systems on existing power units is estimated at about 10% greater than for new units, but it should be recognized that actual applications may be considerably higher due to low service and utility availability, unfavorable physical layout, shutdown requirements, and construction efficiency. Also, the investment cost for a single unit under the central processing concept, Scheme D, is about 6% higher than for a single-site Scheme A system; however, when multiple units are considered, Scheme D investment is less, by as much as 13%.

The lowest cost source materials for makeup magnesium oxide are raw magnesite and dolomite, but these materials may contain considerable undesirable impurities. At least until proven otherwise, calcined magnesite should be used as the primary raw material. It is expected to cost between \$94 and \$140/ton, 100% MgO delivered, depending on shipping destination.

Magnesia process operating costs have been examined under both regulated (cost of money and income taxes included) and nonregulated bases for 7,000 hr/yr operation. In most respects, the results are similar to investment requirements in that Scheme C is the least costly variation, existing units are more expensive to operate, oil-fired systems have lower costs than coal-fired systems, and Scheme D for a single-unit system is more costly than Scheme A, but on a multiple unit basis, is less expensive. One notable exception to the investment relationships is that operating costs are for oil-fired Scheme B systems just slightly less costly than comparable Scheme A systems. For coal-fired systems, Scheme A is slightly lower. The explanation for this disparity lies almost solely with fuel oil requirements for reheating the humidified stack gas. In both coal-fired systems, the gas is totally humidified to a saturation temperature of approximately 127° F as it passes through both the particulate and SO_2 scrubbers. In the oil-fired system design, however, Grillo indicates only partial saturation to a temperature of 140° F in the single-spray absorber used for MgO-MnO_2 scrubbing whereas Scheme A is assumed to be totally saturated to 127° F. Although the resulting different scrubber temperatures could easily be questioned, nevertheless, the lower requirements for reheating the partially saturated Scheme B scrubber gas to 175° F accounts for the lower Scheme B operating cost in the oil-fired system comparison.

Regulated operating costs range from $3.62-7.75/ton of coal burned for the coal-fired units and from $0.50-1.34/barrel of oil for oil-fired units. Sulfuric acid manufacturing costs by magnesia scrubbing range from $41.53-178.97/ton of acid. For comparable cases, the limestone-wet scrubbing process is estimated at $3.24-5.80/ton of coal burned and $0.46-1.03/barrel of oil burned when a low cost limestone and on-site solids disposal are utilized. Values for the high cost limestone and off-site solids disposal range from $5.08-7.22/ton of coal burned and $0.52-1.19/barrel of oil burned. Except for the 200-mw units, the magnesia system operating costs fall between the high and low cost limestone estimates. Premium costs for low sulfur coal and low sulfur oil are quite variable, depending on location delivered, but values appear to range from $2-8/ton of coal and $0.75-2/barrel of oil.

Under Scheme D, the operating costs for producing acid in a central plant is estimated to range from $15.35-36.52/ton of acid when magnesium sulfite is supplied from one or more 200-mw, 500-mw, or 1000-mw scrubbing systems at no cost other than shipping expense. This acid cost is $2-23 higher than that from acid plants burning elemental sulfur at current prices ($24-27/long ton of sulfur).

Fairly large quantities of sulfuric acid can be produced from the SO_2 emitted by power plants, on the order of 378 tons/day for a 500-mw unit burning coal containing 3.5% sulfur, or 2,000 tons/day for a central process acid plant equivalent to 3000-mw. With a projected annual growth rate of 4.6%, marketing large quantities of byproduct sulfuric acid from power plants will take special planning. Probably, the best end-use market is the phosphate fertilizer industry and the prime plant locations would be in the Midwest near high sulfur coal and large consumers of phosphate fertilizers. Even in this area, competition will be rough and average net revenue can not often be expected to exceed $8/ton of acid for single power unit applications. Since flexibility will be limited, in that acid demand will not coincide with production, heavy discounting may be necessary to assure disposal of the product. For central process acid plants, flexibility is higher and, assuming more independence from the fertilizer market, an average net revenue of $12/ton is more appropriate.

Final economic potential of the magnesia schemes is considered by three different financial procedures: regulated profitability as practiced by the power industry, nonregulated profitability as used in the chemical industry, and a combination of the two–cooperative economics. Under regulated economics, a limited, fixed return on investment is provided; for nonregulated economics, profitability depends entirely on competitive forces. For alternatives under regulated economics, the evaluation compares only the resultant cost effects to power consumers; with nonregulated alternative appraisal, the most profitable route is derived. In cooperative economics, the portion of investment under regulation is so evaluated, and that under nonregulation is subjected to profitability analysis.

Regardless of the financial basis of evaluation, the measure of potential for any process scheme depends on several factors including:

1. Plant size.
2. Sulfur content of fuel.
3. Fuel type.
4. Plant status (new or existing unit at the time the SO_2 removal process is installed).
5. Operating onstream time.
6. Revenue from sale of product(s) and for operations at more than one site (Scheme D).
7. Shipping costs of transferred material.

Although these variables can be examined individually, the magnitude of each depends on the level chosen for the others.

Using regulated economics, the single-site magnesia Schemes A, B, and C are compared to each other and both high (metropolitan) and low (rural) cost limestone scrubbing. Scheme C is the lowest cost magnesia process for coal-fired units with Scheme B only slightly higher than Scheme A. Only Scheme C applied to power units larger than 500-600-mw is less expensive than low cost limestone scrubbing; however, when compared with high cost ($6/ton limestone, off-site solids disposal at $6/ton) limestone scrubbing, all three magnesia schemes are less costly for units above 300-400-mw in size. For oil-fired units, results are similar for Schemes A and B; Scheme C (solution scrubbing) is not applicable to oil-fired units.

Usually increasing sulfur content of fuel or annual onstream time improves the economics; however, since it costs more than $8/ton to manufacture the acid from free $MgSO_3$, an increased quantity of throughput, at least up to the levels reviewed, increases total cost of magnesia schemes.

From this data, it can be seen that when regulated power industry funding is necessary for single-site applications, only large units should be considered for magnesia scrubbing-regeneration.

When investment is provided by a nonregulated company, it can be assumed that some fee or payment might be charged to the power company for the service performed; a maximum could be the cost of comparable limestone-wet scrubbing and a minimum would be zero. Under the terms of maximum payment equivalent to high cost limestone scrubbing and \$8/ton revenue, the best profitability of the cases examined is for Scheme C on a new 1000-mw, coal-fired unit–22.8% interest rate of return or 4.0 year payout. Without any payment, all cases evaluated have negative interest rates of return and no payouts (which means original capital investment was not even recovered). The most profitable case for Scheme A, again assuming the high equivalent limestone payment, is a new, coal-fired (3.5% S), 1000-mw unit with an interest rate of return of 18.1% and a payout in 4.8 years. It should be stated, however, that projections of the profitability curves indicate that little improvement can be achieved by increasing unit size above 1000-mw for single-site applications.

For applications where competition is a low cost limestone scrubbing system, an expected lower payment restricts the magnesia process profitability considerably. Under nonregulated economics, \$8/ton acid revenue, and low or no air pollution control payment, single-site magnesia processes attached to a power unit would not be attractive as a chemical industry investment.

When investment arrangements are cooperative (that is, the scrubbing-drying operation is provided by power company funds and the regeneration-acid unit built by nonregulated company capital), the best qualities of the magnesia process are utilized. Not only financial responsibility, but also operating and marketing requirements are more compatible with power plant operation and chemical manufacturing. Assuming supply of magnesium sulfite to the central regeneration plant from several power plant sources, acid manufacture becomes independent of the cyclic nature of power demand and chemical plant operation can be more readily optimized.

A major obstacle to such arrangement, however, is that acid revenue alone will not produce sufficient profitability to justify nonregulated capital investment in the regeneration-acid plant. The incentive for power companies to invest in magnesia scrubbing is much stronger since magnesia scrubbing is less expensive than limestone scrubbing when magnesium sulfite is swapped for magnesium oxide. To improve the potential for sulfuric acid plant investment, another revenue source can be sought; that of charging for recycle MgO. This should be feasible as long as the price charged permits magnesia scrubbing costs to be less than limestone scrubbing.

For 1000-mw size magnesia scrubbing systems, the cost of recycle MgO would need to be limited to \$10-15/ton and for 500-mw systems, \$15-20/ton when competition is a low cost limestone scrubbing system. However, as the unit size of the individual scrubbing-drying system decreases, or the cost of a limestone scrubbing system increases, the possible price of recycle MgO increases. As the recycle MgO revenue rises, the profitability potential of the central process concept becomes more and more attractive.

For a 3000-mw equivalent central acid plant with magnesium sulfite supplied by six 500-mw slurry scrubbing units within a 50-mile radius, and net revenue of \$12/ton of acid and \$15/ton for recycle MgO, the interest rate of return is only 8.7% with a payout of 6.5 years. If competitive limestone scrubbing has a high cost (\$6/ton limestone, off-site solids disposal at \$6/ton), approximately \$55/ton can be charged for recycle MgO which would permit an interest rate of return of 39.7% and a payout of 2.4 years. Therefore, depending on competitive costs of alternate methods of SO_2 control, the attractiveness of the magnesia central process concept can range from poor to excellent.

Since the data presented in figure 126 indicate that a higher price can be charged for recycle MgO as the power unit size decreases, it can be concluded that the greatest profitability of the central process concept lies with smaller scrubbing systems tied to large acid plants. For instance, a 3000-mw equivalent acid plant supplied by fifteen 200-mw scrubbing-drying systems within a 50-mile radius could earn a 40.6% interest rate of return if \$55/ton is obtained for recycle MgO. When a low cost limestone process is the competition, and only \$25/ton can be obtained for the recycle absorbent, the interest rate of return would be 17.2% which is still attractive.

In the analysis of the central processing concept, the effect of shipping cost for transferring $MgSO_3$ and MgO between the plants deserves particular attention. Shipping cost is not a large fraction (7-8% for 50-miles) of total operation cost; therefore, it is not surprising to find that interest rates of return are decreased only about 1-3% for every 25-miles distance. Because shipping rates are unchanged in the first 50-miles, there is no effect inside this radius.

The effect of acid revenue on economic potential varies with each of the three financial arrangements studied. If, instead of \$8/ton of acid, \$16-20/ton could be obtained, the magnesia process would be competitive with low cost limestone scrubbing for single-site applications under regulated economics. Under nonregulated profitability, an increase of 250-300% in acid revenue (\$20-24/ton) would be necessary to make single magnesia scrubbing-regeneration systems attractive when coupled with only a low equivalent payment. With the central process concept, an increase in acid revenue from \$12/ton-20/ton would permit attractive profitability since such large volumes of acid are involved.

In summation, it can be concluded that most magnesia scrubbing systems would be economically attractive under any financial arrangement if competition for SO_2 control is high cost limestone scrubbing, and high premium, low sulfur fuel. Locations meeting these conditions would be mostly in midwestern and eastern metropolitan areas of the United States and western Europe. In such areas where limestone cost is relatively low and solids disposal is not unduly expensive, magnesia scrubbing-regeneration might possibly be attractive, but unexpectedly high acid prices would have to be obtained. If total system financing must be under regulated conditions, only large power units should be considered for application of magnesia scrubbing-regeneration.

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    1. Oxides of nitrogen can best be kept low by depressing peak temperatures to about 3050° F.

    2. If this is not possible, then the secondary combustion zone should be cooled rapidly to this temperature.

    3. Carbon monoxide concentrations can be limited by rapid induction of secondary air.

    4. Hydrocarbon concentrations can be controlled by designing for well-seated, stable flames.

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APPENDIX A

Cost Tables

Table A-1. Summary of Estimated Fixed Investment:[a] Scheme A—Magnesia Slurry Scrubbing-Regeneration Process

(200-mw new coal-fired power unit, 3.5% S in fuel; 6.5 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	200,000
Particulate scrubbers (2 scrubbers with surge tanks, agitators, pumps, and fly ash neutralization and disposal facilities)	1,445,000
Sulfur dioxide scrubbers (2 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	1,602,000
Optional bypass duct around scrubbers	209,000
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	416,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$ storage hopper)	470,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	635,000
Magnesium oxide slurrying (MgO unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	140,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	1,495,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	108,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	94,000
Control room building, including motor controls, laboratory, and lockers	150,000
Service facilities and buildings allocation for maintenance, shops, and offices	410,000
Subtotal direct investment	7,374,000
Engineering design and supervision	664,000
Construction expense	811,000
Contractor fees	442,000
Contingency	959,000
Subtotal fixed capital investment	10,250,000
Allowance for startup and modifications	1,025,000
Interest during construction (8%/annum rate)	410,000
Total fixed capital investment	11,685,000

[a] Basis:

Stack gas reheat to 175° F. by indirect steam reheat.
Direct disposal of neutralized ash slurry (15% solids) with recycle of water to fly ash scrubber.
Disposal pond distance of 1 mile.
Midwest plant location—1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-2. Summary of Estimated Fixed Investment:[a]
Scheme A—Magnesia Slurry Scrubbing-Regeneration Process
(200-mw existing coal-fired power unit, 3.5% S in fuel;
6.7 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	260,000
Particulate scrubbers (2 scrubbers with surge tanks, agitators, pumps, and fly ash neutralization and disposal facilities)	1,763,000
Sulfur dioxide scrubbers (2 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	1,823,000
Optional bypass duct around scrubbers	—
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	432,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$ storage hopper)	486,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	656,000
Magnesium oxide slurrying (MgO unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	145,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	1,552,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	112,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	130,000
Control room building, including motor controls, laboratory, and lockers	170,000
Service facilities and buildings allocation for maintenance, shops, and offices	440,000
Subtotal direct investment	7,969,000
Engineering design and supervision	797,000
Construction expense	1,036,000
Contractor fees	638,000
Contingency	1,036,000
Subtotal fixed capital investment	11,476,000
Allowance for startup and modifications	1,148,000
Interest during construction (8%/annum rate)	459,000
Total fixed capital investment	13,083,000

[a] Basis:
Stack gas reheat to 175°F. by direct oil-fired reheat.
Direct disposal of neutralized ash slurry (15% solids) with recycle of water to fly ash scrubber.
Disposal pond distance of 1 mile.
Midwest plant location–1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-3. Summary of Estimated Fixed Investment:[a] Scheme A—Magnesia Slurry Scrubbing-Regeneration Process

(500-mw new coal-fired power unit, 2.0% S in fuel; 9.0 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	250,000
Particulate scrubbers (4 scrubbers with surge tanks, agitators, pumps, and fly ash neutralization and disposal facilities)	3,194,000
Sulfur dioxide scrubbers (4 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	3,505,000
Optional bypass duct around scrubbers	454,000
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	534,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$ storage hopper)	575,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	777,000
Magnesium oxide slurrying (MgO unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	180,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	1,918,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	138,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	121,000
Control room building, including motor controls, laboratory, and lockers	200,000
Service facilities and buildings allocation for maintenance, shops, and offices	640,000
Subtotal direct investment	12,486,000
Engineering design and supervision	874,000
Construction expense	1,124,000
Contractor fees	499,000
Contingency	1,498,000
Subtotal fixed capital investment	16,481,000
Allowance for startup and modifications	1,648,000
Interest during construction (8%/annum rate)	659,000
Total fixed capital investment	18,788,000

[a] Basis:

Stack gas reheat to 175°F. by indirect steam reheat.
Direct disposal of neutralized ash slurry (15% solids) with recycle of water to fly ash scrubber.
Disposal pond distance of 1 mile.
Midwest plant location–1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-4. Summary of Estimated Fixed Investment:[a]
Scheme A—Magnesia Slurry Scrubbing-Regeneration Process
(500-mw new coal-fired power unit, 3.5% S in fuel;
15.8 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	270,000
Particulate scrubbers (4 scrubbers with surge tanks, agitators, pumps, and fly ash neutralization and disposal facilities)	3,194,000
Sulfur dioxide scrubbers (4 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	3,528,000
Optional bypass duct around scrubbers	454,000
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	785,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$ storage hopper)	810,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	1,094,000
Magnesium oxide slurrying (MgO unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	264,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	2,821,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	203,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	178,000
Control room building, including motor controls, laboratory, and lockers	200,000
Service facilities and buildings allocation for maintenance, shops, and offices	640,000
Subtotal direct investment	14,441,000
Engineering design and supervision	1,011,000
Construction expense	1,300,000
Contractor fees	578,000
Contingency	1,733,000
Subtotal fixed capital investment	19,063,000
Allowance for startup and modifications	1,906,000
Interest during construction (8%/annum rate)	763,000
Total fixed capital investment	21,732,000

[a] Basis:
Stack gas reheat to 175° F. by indirect steam reheat.
Direct disposal of neutralized ash slurry (15% solids) with recycle of water to fly ash scrubber.
Disposal pond distance of 1 mile.
Midwest plant location—1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-5. Summary of Estimated Fixed Investment:[a] Scheme A—Magnesia Slurry Scrubbing-Regeneration Process

(500-mw new coal-fired power unit, 5.0% S in fuel; 22.5 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	290,000
Particulate scrubbers (4 scrubbers with surge tanks, agitators, pumps, and fly ash neutralization and disposal facilities)	3,194,000
Sulfur dioxide scrubbers (4 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	3,551,000
Optional bypass duct around scrubbers	454,000
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	1,005,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$ storage hopper)	1,004,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	1,357,000
Magnesium oxide slurrying (MgO unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	338,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	3,611,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	260,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	228,000
Control room building, including motor controls, laboratory, and lockers	200,000
Service facilities and buildings allocation for maintenance, shops, and offices	640,000
Subtotal direct investment	16,132,000
Engineering design and supervision	1,129,000
Construction expense	1,452,000
Contractor fees	645,000
Contingency	1,936,000
Subtotal fixed capital investment	21,294,000
Allowance for startup and modifications	2,129,000
Interest during construction (8%/annum rate)	852,000
Total fixed capital investment	24,275,000

[a] Basis:

Stack gas reheat to 175°F. by indirect steam reheat.
Direct disposal of neutralized ash slurry (15% solids) with recycle of water to fly ash scrubber.
Disposal pond distance of 1 mile.
Midwest plant location—1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-6. Summary of Estimated Fixed Investment:[a] Scheme A–Magnesia Slurry Scrubbing-Regeneration Process

(500-mw existing coal-fired power unit, 3.5% S in fuel; 16.1 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	350,000
Particulate scrubbers (4 scrubbers with surge tanks, agitators, pumps, and fly ash neutralization and disposal facilities)	3,919,000
Sulfur dioxide scrubbers (4 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	4,056,000
Optional bypass duct around scrubbers	–
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	801,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$ storage hopper)	818,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	1,105,000
Magnesium oxide slurrying (MgO unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	269,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	2,877,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	207,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	242,000
Control room building, including motor controls, laboratory, and lockers	230,000
Service facilities and buildings allocation for maintenance, shops, and offices	680,000
Subtotal direct investment	15,554,000
Engineering design and supervision	1,244,000
Construction expense	1,866,000
Contractor fees	933,000
Contingency	2,022,000
Subtotal fixed capital investment	21,619,000
Allowance for startup and modifications	2,162,000
Interest during construction (8%/annum rate)	865,000
Total fixed capital investment	24,646,000

[a] Basis:
Stack gas reheat to 175°F. by direct oil-fired reheat.
Direct disposal of neutralized ash slurry (15% solids) with recycle of water to fly ash scrubber.
Disposal pond distance of 1 mile.
Midwest plant location–1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-7. Summary of Estimated Fixed Investment:[a]
Scheme A–Magnesia Slurry Scrubbing-Regeneration Process
(1000-mw new coal-fired power unit, 3.5% S in fuel; 30.5 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	400,000
Particulate scrubbers (4 scrubbers with surge tanks, agitators, pumps, and fly ash neutralization and disposal facilities)	5,055,000
Sulfur dioxide scrubbers (4 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	5,698,000
Optional bypass duct around scrubbers	631,000
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	1,248,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$ storage hopper)	1,207,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	1,630,000
Magnesium oxide slurrying (MgO unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	420,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	4,485,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	323,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	283,000
Control room building, including motor controls, laboratory, and lockers	250,000
Service facilities and buildings allocation for maintenance, shops, and offices	890,000
Subtotal direct investment	22,520,000
Engineering design and supervision	1,351,000
Construction expense	1,802,000
Contractor fees	901,000
Contingency	2,477,000
Subtotal fixed capital investment	29,051,000
Allowance for startup and modifications	2,905,000
Interest during construction (8%/annum rate)	1,162,000
Total fixed capital investment	33,118,000

[a] Basis:

Stack gas reheat to 175° F. by indirect steam reheat.
Direct disposal of neutralized ash slurry (15% solids) with recycle of water to fly ash scrubber.
Disposal pond distance of 1 mile.
Midwest plant location–1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-8. Summary of Estimated Fixed Investment:[a]
Scheme A–Magnesia Slurry Scrubbing-Regeneration Process
(1000-mw existing coal-fired power unit, 3.5% S in fuel;
31.6 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	500,000
Particulate scrubbers (4 scrubbers with surge tanks, agitators, pumps, and fly ash neutralization and disposal facilities)	6,114,000
Sulfur dioxide scrubbers (4 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	6,432,000
Optional bypass duct around scrubbers	–
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	1,272,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$ storage hopper)	1,231,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	1,663,000
Magnesium oxide slurrying (MgO unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	428,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	4,570,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	329,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	383,000
Control room building, including motor controls, laboratory, and lockers	290,000
Service facilities and buildings allocation for maintenance, shops, and offices	950,000
Subtotal direct investment	24,162,000
Engineering design and supervision	1,691,000
Construction expense	2,175,000
Contractor fees	1,208,000
Contingency	2,899,000
Subtotal fixed capital investment	32,135,000
Allowance for startup and modifications	3,214,000
Interest during construction (8%/annum rate)	1,285,000
Total fixed capital investment	36,634,000

[a] Basis:
Stack gas reheat to 175°F. by direct oil-fired reheat.
Direct disposal of neutralized ash slurry (15% solids) with recycle of water to fly ash scrubber.
Disposal pond distance of 1 mile.
Midwest plant location–1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-9. Summary of Estimated Fixed Investment:[a] Scheme A–Magnesia Slurry Scrubbing-Regeneration Process

(200-mw new oil-fired power unit, 2.5% S in fuel; 3.4 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	130,000
Sulfur dioxide scrubbers (2 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	1,517,000
Optional bypass duct around scrubbers	103,000
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	243,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_4$ storage hopper)	300,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	405,000
Magnesium oxide slurrying (MgO unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	82,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	875,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	63,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	84,000
Control room building, including motor controls, laboratory, and lockers	150,000
Service facilities and buildings allocation for maintenance, shops, and offices	270,000
Subtotal direct investment	4,222,000
Engineering design and supervision	380,000
Construction expense	464,000
Contractor fees	253,000
Contingency	549,000
Subtotal fixed capital investment	5,868,000
Allowance for startup and modifications	587,000
Interest during construction (8%/annum rate)	235,000
Total fixed capital investment	6,690,000

[a] Basis:
Stack gas reheat to 175°F. by direct oil-fired reheat.
Midwest plant location–1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-10. Summary of Estimated Fixed Investment:[a]
Scheme A—Magnesia Slurry Scrubbing-Regeneration Process
(500-mw new oil-fired power unit, 1.0% S in fuel;
3.4 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	200,000
Sulfur dioxide scrubbers (4 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	3,428,000
Optional bypass duct around scrubbers	228,000
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	243,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$ storage hopper)	292,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	394,000
Magnesium oxide slurrying (MgO unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	82,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	875,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	63,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	116,000
Control room building, including motor controls, laboratory, and lockers	200,000
Service facilities and buildings allocation for maintenance, shops, and offices	450,000
Subtotal direct investment	6,571,000
Engineering design and supervision	460,000
Construction expense	591,000
Contractor fees	263,000
Contingency	789,000
Subtotal fixed capital investment	8,674,000
Allowance for startup and modifications	867,000
Interest during construction (8%/annum rate)	347,000
Total fixed capital investment	9,888,000

[a] Basis:
Stack gas reheat to 175°F. by direct oil-fired reheat.
Midwest plant location—1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-11. Summary of Estimated Fixed Investment:[a] Scheme A—Magnesia Slurry Scrubbing-Regeneration Process

(500-mw new oil-fired power unit, 2.5% S in fuel; 8.4 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	220,000
Sulfur dioxide scrubbers (4 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	3,450,000
Optional bypass duct around scrubbers	228,000
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	455,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$ storage hopper)	510,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	689,000
Magnesium oxide slurrying (MgO unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	153,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	1,636,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	118,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	157,000
Control room building, including motor controls, laboratory, and lockers	200,000
Service facilities and buildings allocation for maintenance, shops, and offices	450,000
Subtotal direct investment	8,266,000
Engineering design and supervision	579,000
Construction expense	744,000
Contractor fees	331,000
Contingency	992,000
Subtotal fixed capital investment	10,912,000
Allowance for startup and modifications	1,091,000
Interest during construction (8%/annum rate)	436,000
Total fixed capital investment	12,439,000

[a] Basis:

Stack gas reheat to 175°F. by direct oil-fired reheat.

Midwest plant location–1972 costs.

Minimum in process storage; only pumps are spared; ash pond not included.

Table A-12. Summary of Estimated Fixed Investment:[a] Scheme A—Magnesia Slurry Scrubbing-Regeneration Process

(500-mw new oil-fired power unit, 4.0% S in fuel; 13.5 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	240,000
Sulfur dioxide scrubbers (4 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	3,473,000
Optional bypass duct around scrubbers	228,000
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	636,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$ storage hopper)	680,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	919,000
Magnesium oxide slurrying (MgO unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	214,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	2,285,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	164,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	192,000
Control room building, including motor controls, laboratory, and lockers	200,000
Service facilities and buildings allocation for maintenance, shops, and offices	450,000
Subtotal direct investment	9,681,000
Engineering design and supervision	678,000
Construction expense	871,000
Contractor fees	387,000
Contingency	1,162,000
Subtotal fixed capital investment	12,779,000
Allowance for startup and modifications	1,278,000
Interest during construction (8%/annum rate)	511,000
Total fixed capital investment	14,568,000

[a] Basis:

Stack gas reheat to 175° F. by direct oil-fired reheat.
Midwest plant location—1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-13. Summary of Estimated Fixed Investment:[a] Scheme A—Magnesia Slurry Scrubbing-Regeneration Process

(500-mw existing oil-fired power unit, 2.5% S in fuel; 8.6 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	250,000
Sulfur dioxide scrubbers (4 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	4,036,000
Optional bypass duct around scrubbers	—
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	463,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$ storage hopper)	518,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	700,000
Magnesium oxide slurrying (MgO unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	156,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	1,664,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	120,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	158,000
Control Rroom building, including motor controls, laboratory, and lockers	230,000
Service facilities and buildings allocation for maintenance, shops, and offices	490,000
Subtotal direct investment	8,785,000
Engineering design and supervision	703,000
Construction expense	1,054,000
Contractor fees	527,000
Contingency	1,142,000
Subtotal fixed capital investment	12,211,000
Allowance for startup and modifications	1,221,000
Interest during construction (8%/annum rate)	488,000
Total fixed capital investment	13,920,000

[a] Basis:

Stack gas reheat to 175°F. by direct oil-fired reheat.
Midwest plant location—1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-14. Summary of Estimated Fixed Investment:[a] Scheme A—Magnesia Slurry Scrubbing-Regeneration Process

(1000-mw new oil-fired power unit, 2.5% S in fuel; 16.3 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	360,000
Sulfur dioxide scrubbers (4 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	5,369,000
Optional bypass duct around scrubbers	317,000
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	730,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$ storage hopper)	761,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	1,028,000
Magnesium oxide slurrying (MgO unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	246,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	2,624,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	189,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	249,000
Control room building, including motor controls, laboratory, and lockers	250,000
Service facilities and buildings allocation for maintenance, shops, and offices	720,000
Subtotal direct investment	12,843,000
Engineering design and supervision	771,000
Construction expense	1,027,000
Contractor fees	514,000
Contingency	1,413,000
Subtotal fixed capital investment	16,568,000
Allowance for startup and modifications	1,657,000
Interest during construction (8%/annum rate)	663,000
Total fixed capital investment	18,888,000

[a] Basis:
Stack gas reheat to 175° F. by direct oil-fired reheat.
Midwest plant location—1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-15. Summary of Estimated Fixed Investment:[a] Scheme B—MgO-MnO_2 Slurry Scrubbing-Regeneration Process

(200-mw new coal-fired power unit, 3.5% S in fuel; 6.5 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	200,000
Particulate scrubbers (2 scrubbers with surge tanks, agitators, pumps, and fly ash neutralization and disposal facilities)	1,445,000
Sulfur dioxide scrubbers (4 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	1,481,000
Optional bypass duct around scrubbers	209,000
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	393,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$-$MgSO_4$ storage hopper)	497,000
Calcining (fluid bed calcining system, fans, MgO-MnO_2 and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	751,000
Magnesium oxide-manganese oxide slurrying (MgO and MnO_2 unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	273,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	1,547,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	108,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	102,000
Control room building, including motor controls, laboratory, and lockers	150,000
Service facilities and buildings allocation for maintenance, shops, and offices	410,000
Subtotal direct investment	7,566,000
Engineering design and supervision	681,000
Construction expense	832,000
Contractor fees	454,000
Contingency	984,000
Subtotal fixed capital investment	10,517,000
Allowance for startup and modifications	1,052,000
Interest during construction (8%/annum rate)	421,000
Total fixed capital investment	11,990,000

[a] Basis:
Stack gas reheat to 175°F. by indirect steam reheat.
Direct disposal of neutalized ash slurry (15% solids) with recycle of water to fly ash scrubber.
Disposal pond distance of 1 mile.
Midwest plant location—1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-16. Summary of Estimated Fixed Investment:[a] Scheme B—MgO-MnO$_2$ Slurry Scrubbing-Regeneration Process

(500-mw new coal-fired power unit, 3.5% S in fuel; 15.8 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	270,000
Particulate scrubbers (4 scrubbers with surge tanks, agitators, pumps, and fly ash neutralization and disposal facilities)	3,194,000
Sulfur dioxide scrubbers (8 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	3,299,000
Optional bypass duct around scrubbers	454,000
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	741,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$-$MgSO_4$ storage hopper)	857,000
Calcining (fluid bed calcining system, fans, MgO-MnO$_2$ and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	1,295,000
Magnesium oxide-manganese oxide slurrying (MgO and MnO$_2$ unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	515,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	2,918,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	203,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	192,000
Control room building, including motor controls, laboratory, and lockers	200,000
Service facilities and buildings allocation for maintenance, shops, and offices	640,000
Subtotal direct investment	14,778,000
Engineering design and supervision	1,034,000
Construction expense	1,330,000
Contractor fees	591,000
Contingency	1,773,000
Subtotal fixed capital investment	19,506,000
Allowance for startup and modifications	1,951,000
Interest during construction (8%/annum rate)	780,000
Total fixed capital investment	22,237,000

[a] Basis:
Stack gas reheat to 175° F. by indirect steam reheat.
Direct disposal of neutalized ash slurry (15% solids) with recycle of water to fly ash scrubber.
Disposal pond distance of 1 mile
Midwest plant location—1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-17. Summary of Estimated Fixed Investment:[a]
Scheme B—MgO-MnO_2 Slurry Scrubbing-Regeneration Process
(1000-mw new coal-fired power unit, 3.5% S in fuel;
30.5 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	400,000
Particulate scrubbers (4 scrubbers with surge tanks, agitators, pumps, and fly ash neutralization and disposal facilities)	5,055,000
Sulfur dioxide scrubbers (8 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	5,313,000
Optional bypass duct around scrubbers	631,000
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	1,178,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$-$MgSO_4$ storage hopper)	1,277,000
Calcining (fluid bed calcining system, fans, MgO-MnO_2 and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	1,930,000
Magnesium oxide-manganese oxide slurrying (MgO and MnO_2 unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	819,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	4,639,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	323,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	305,000
Control room building, including motor controls, laboratory, and lockers	250,000
Service facilities and buildings allocation for maintenance, shops, and offices	890,000
Subtotal direct investment	23,010,000
Engineering design and supervision	1,381,000
Construction expense	1,841,000
Contractor fees	920,000
Contingency	2,531,000
Subtotal fixed capital investment	29,683,000
Allowance for startup and modifications	2,968,000
Interest during construction (8%/annum rate)	1,187,000
Total fixed capital investment	33,838,000

[a] Basis:
Stack gas reheat to 175° F. by indirect steam reheat.
Direct disposal of neutalized ash slurry (15% solids) with recycle of water to fly ash scrubber.
Disposal pond distance of 1 mile.
Midwest plant location–1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-18. Summary of Estimated Fixed Investment:[a] Scheme B—MgO-MnO_2 Slurry Scrubbing-Regeneration Process

(200-mw new oil-fired power unit, 2.5% S in fuel; 3.4 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	130,000
Sulfur dioxide scrubbers (4 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	1,398,000
Optional bypass duct around scrubbers	103,000
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	230,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$-$MgSO_4$ storage hopper)	317,000
Calcining (fluid bed calcining system, fans, MgO and MnO_2 and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	479,000
Magnesium oxide-manganese oxide slurrying (MgO and MnO_2 unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	160,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	905,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	63,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	90,000
Control room building, including motor controls, laboratory, and lockers	150,000
Service facilities and buildings allocation for maintenance, shops, and offices	270,000
Subtotal direct investment	4,295,000
Engineering design and supervision	387,000
Construction expense	472,000
Contractor fees	258,000
Contingency	558,000
Subtotal fixed capital investment	5,970,000
Allowance for startup and modifications	597,000
Interest during construction (8%/annum rate)	239,000
Total fixed capital investment	6,806,000

[a] Basis:
Stack gas reheat to 175° F. by direct oil-fired reheat.
Midwest plant location—1972 costs.
Minimum in process storage; only pumps are spared.

Table A-19. Summary of Estimated Fixed Investment:[a] Scheme B—MgO-MnO$_2$ Slurry Scrubbing-Regeneration Process

(500-mw new oil-fired power unit, 2.5% S in fuel; 8.4 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	220,000
Sulfur dioxide scrubbers (8 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	3,185,000
Optional bypass duct around scrubbers	228,000
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	430,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$-$MgSO_4$ storage hopper)	540,000
Calcining (fluid bed calcining system, fans, MgO-MnO$_2$ and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	816,000
Magnesium oxide-manganese oxide slurrying (MgO and MnO$_2$ unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	299,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	1,692,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	118,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	169,000
Control room building, including motor controls, laboratory, and lockers	200,000
Service facilities and buildings allocation for maintenance, shops, and offices	450,000
Subtotal direct investment	8,347,000
Engineering design and supervision	584,000
Construction expense	751,000
Contractor fees	334,000
Contingency	1,002,000
Subtotal fixed capital investment	11,018,000
Allowance for startup and modifications	1,102,000
Interest during construction (8%/annum rate)	441,000
Total fixed capital investment	12,561,000

[a] Basis:

Stack gas reheat to 175° F. by direct oil-fired reheat.
Midwest plant location–1972 costs.
Minimum in process storage; only pumps are spared.

Table A-20. Summary of Estimated Fixed Investment:[a] Scheme B—MgO-MnO_2 Slurry Scrubbing-Regeneration Process

(1000-mw new oil-fired power unit, 2.5% S in fuel; 16.3 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	360,000
Sulfur dioxide scrubbers (8 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	4,996,000
Optional bypass duct around scrubbers	317,000
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	689,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$-$MgSO_4$ storage hopper)	806,000
Calcining (fluid bed calcining system, fans, MgO-MnO_2 and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	1,217,000
Magnesium oxide-manganese oxide slurrying (MgO and MnO_2 unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	479,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	2,714,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	189,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	269,000
Control room building, including motor controls, laboratory, and lockers	250,000
Service facilities and buildings allocation for maintenance, shops, and offices	720,000
Subtotal direct investment	13,006,000
Engineering design and supervision	780,000
Construction expense	1,040,000
Contractor fees	520,000
Contingency	1,431,000
Subtotal fixed capital investment	16,777,000
Allowance for startup and modifications	1,678,000
Interest during construction (8%/annum rate)	671,000
Total fixed capital investment	19,126,000

[a] Basis:

Stack gas reheat to 175°F. by direct oil-fired reheat.
Midwest plant location—1972 costs.
Minimum in process storage; only pumps are spared.

Table A-21. Summary of Estimated Fixed Investment:[a] Scheme C–Magnesia Clear Liquor Scrubbing-Regeneration Process

(200-mw-new coal-fired power unit, 3.5% S in fuel; 5.5 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	200,000
Particulate and sulfur dioxide scrubbers (2 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	1,940,000
Optional bypass duct around scrubbers	138,000
Solution-slurry processing (thickner, filters, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	784,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$ storage hopper)	429,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	569,000
Magnesium oxide slurrying (MgO unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	133,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	1,348,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	78,000
Fuel loil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	83,000
Control room building, including motor controls, laboratory, and lockers	150,000
Service facilities and buildings allocation for maintenance, shops, and offices	410,000
Subtotal direct investment	6,262,000
Engineering design and supervision	564,000
Construction expense	689,000
Contractor fees	376,000
Contingency	814,000
Subtotal fixed capital investment	8,705,000
Allowance for startup and modifications	870,000
Interest during construction (8%/annum rate)	348,000
Total fixed capital investment	9,923,000

[a] Basis:

Stack gas reheat to 175° F. by indirect steam reheat.
Direct disposal of neutalized ash slurry (15% solids) with recycle of water to fly ash scrubber.
Disposal pond distance of 1 mile.
Midwest plant location–1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-22. Summary of Estimated Fixed Investment:[a]
Scheme C—Magnesia Clear Liquor Scrubbing-Regeneration Process

(500-mw new coal-fired power unit, 3.5% S in fuel; 13.5 tons/hr H_2SO_4*)*

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	270,000
Particulate and sulfur dioxide scrubbers (4 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	4,327,000
Optional bypass duct around scrubbers	300,000
Solution-slurry processing (thickner, filters, tanks, pumps, agitators, and heating coils, purification facilities, centrifuges, and conveyors)	1,479,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$ storage hopper)	740,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	981,000
Magnesium oxide slurrying (MgO unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	251,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	2,544,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	147,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	157,000
Control room building, including motor controls, laboratory, and lockers	200,000
Service facilities and buildings allocation for maintenance, shops, and offices	640,000
Subtotal direct investment	12,036,000
Engineering design and supervision	843,000
Construction expense	1,083,000
Contractor fees	481,000
Contingency	1,444,000
Subtotal fixed capital investment	15,887,000
Allowance for startup and modifications	1,589,000
Interest during construction (8%/annum rate)	635,000
Total fixed capital investment	18,111,000

[a] Basis:

Stack gas reheat to 175°F. by indirect steam reheat.
Direct disposal of neutalized ash slurry (15% solids) with recycle of water to fly ash scrubber.
Disposal pond distance of 1 mile.
Midwest plant location—1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-23. Summary of Estimated Fixed Investment:[a] Scheme C—Magnesia Clear Liquor Scrubbing-Regeneration Process

(1000-mw new coal-fired power unit, 3.5% S in fuel; 26.1 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	400,000
Particulate and sulfur dioxide scrubbers (4 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	6,925,000
Optional bypass duct around scrubbers	417,000
Solution-slurry processing (thickner, filters, tanks, pumps, agitators, and heating coils, purification facilities, centrifuges, and conveyors)	2,352,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$ storage hopper)	1,103,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors)	1,462,000
Magnesium oxide slurrying (MgO unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	399,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	4,045,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	234,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	250,000
Control room building, including motor controls, laboratory, and lockers	250,000
Service facilities and buildings allocation for maintenance, shops, and offices	890,000
Subtotal direct investment	18,727,000
Engineering design and supervision	1,124,000
Construction expense	1,498,000
Contractor fees	749,000
Contingency	2,060,000
Subtotal fixed capital investment	24,158,000
Allowance for startup and modifications	2,416,000
Interest during construction (8%/annum rate)	966,000
Total fixed capital investment	27,540,000

[a] Basis:

Stack gas reheat to 175°F. by indirect steam reheat.
Direct disposal of neutalized ash slurry (15% solids) with recycle of water to fly ash scrubber.
Disposal pond distance of 1 mile.
Midwest plant location--1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-24. Summary of Estimated Fixed Investment:[a]
Scheme D--Magnesia Slurry Scrubbing-Drying Unit
Central Processing Concept

(200-mw new coal-fired power unit, 3.5% S in fuel: 7.8 tons/hr $MgSO_3$)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	130,000
Particulate scrubbers (2 scrubbers with surge tanks, agitators, pumps, and fly ash neutralization and disposal facilities)	1,445,000
Sulfur dioxide scrubbers (2 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	1,570,000
Optional bypass duct around scrubbers	205,000
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	408,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$ storage hopper, and loading system)	478,000
Magnesium oxide slurrying (MgO unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	165,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	55,000
Control room building, including motor controls, laboratory, and lockers	105,000
Service facilities and buildings allocation for maintenance, shops, and offices	28,000
Subtotal direct investment	4,841,000
Engineering design and supervision	436,000
Construction expense	533,000
Contractor fees	290,000
Contingency	629,000
Subtotal fixed capital investment	6,729,000
Allowance for startup and modifications	673,000
Interest during construction (8%/annum rate)	269,000
Total fixed capital investment	7,671,000

[a] Basis:

Stack gas reheat to 175° F. by indirect steam reheat.
Direct disposal of neutralized ash slurry (15% solids) with recycle of water to fly ash scrubber.
Disposal pond distance of 1 mile.
Midwest plant location–1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-25. Summary of Estimated Fixed Investment:[a] Scheme D—Magnesia Regeneration-Sulfuric Acid Unit Central Processing Concept

(Equivalent to 200-mw new coal-fired power unit, 3.5% S in fuel; 5.7 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	270,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors, loading and unloading equipment)	649,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	1,360,000
Tail gas scrubbing (scrubber, tanks, pumps, dryer, conveyor)	184,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	98,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	55,000
Control room building, including motor controls, laboratory, and lockers	100,000
Service facilities and buildings allocation for maintenance, shops and offices	450,000
Subtotal direct investment	3,166,000
Engineering design and supervision	285,000
Construction expense	348,000
Contractor fees	190,000
Contingency	412,000
Subtotal fixed capital investment	4,401,000
Allowance for startup and modifications	440,000
Interest during construction (8%/annum rate)	176,000
Total fixed capital investment	5,017,000

[a] Basis:
Tail gas recovery of 90% SO_2 and SO_3 from acid absorber, reheat to 175° F.
Midwest plant location—1972 costs.
In process storage of 72 hours.

Table A-26. Summary of Estimated Fixed Investment:[a] Scheme D—Magnesia Slurry Scrubbing-Drying Unit Central Processing Concept

(500-mw new coal-fired power unit, 3.5% S in fuel; 19.1 tons/hr $MgSO_3$)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	180,000
Particulate scrubbers (4 scrubbers with surge tanks, agitators, pumps, and fly ash neutralization and disposal facilities)	3,194,000
Sulfur dioxide scrubbers (4 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	3,457,000
Optional bypass duct around scrubbers	445,000
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	769,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, and $MgSO_3$ storage hopper, and loading system)	824,000
Magnesium oxide slurrying (MgO unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	311,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	104,000
Control room building, including motor controls, laboratory, and lockers	140,000
Service facilities and buildings allocation for maintenance, shops, and offices	440,000
Subtotal direct investment	9,864,000
Engineering design and supervision	690,000
Construction expense	888,000
Contractor fees	395,000
Contingency	1,184,000
Subtotal fixed capital investment	13,021,000
Allowance for startup and modifications	1,302,000
Interest during construction (8%/annum rate)	521,000
Total fixed capital investment	14,844,000

[a] Basis:
Stack gas reheat to 175°F. by indirect steam reheat.
Direct disposal of neutalized ash slurry (15% solids) with recycle of water to fly ash scrubber.
Disposal pond distance of 1 mile.
Midwest plant location—1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-27. Summary of Estimated Fixed Investment:[a] Scheme D—Magnesia Regeneration-Sulfuric Acid Unit Central Processing Concept

(Equivalent to 500-mw new coal-fired power unit, 3.5% S in fuel; 13.8 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	370,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors, loading and unloading equipment)	1,118,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	2,567,000
Tail gas scrubbing (scrubber, tanks, pumps, dryer, conveyor)	339,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	185,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	103,000
Control room building, including motor controls, laboratory, and lockers	130,000
Service facilities and buildings allocation for maintenance, shops, and offices	700,000
Subtotal direct investment	5,512,000
Engineering design and supervision	386,000
Construction expense	496,000
Contractor fees	220,000
Contingency	661,000
Subtotal fixed capital investment	7,275,000
Allowance for startup and modifications	728,000
Interest during construction (8%/annum rate)	291,000
Total fixed capital investment	8,294,000

[a] Basis:
Tail gas recovery of 90% SO_2 and SO_3 from acid absorber, reheat to 175° F.
Midwest plant location—1972 costs.
In process storage of 72 hours.

Table A-28. Summary of Estimated Fixed Investment:[a] Scheme D—Magnesia Slurry Scrubbing-Drying Unit Central Processing Concept

(1000-mw new coal-fired power unit, 3.5% S in fuel; 36.9 tons/hr $MgSO_3$)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	270,000
Particulate scrubbers (4 scrubbers with surge tanks, agitators, pumps, and fly ash neutralization and disposal facilities)	5,055,000
Sulfur dioxide scrubbers (4 scrubbers with surge tanks, agitators, pumps, mist eliminators, flue gas reheaters, and fans)	5,584,000
Optional bypass duct around scrubbers	618,000
Slurry processing (screens, tanks, pumps, agitators and heating coils, purification facilities, centrifuges, and conveyors)	1,223,000
Drying (fluid bed drying system, fans, combustion chamber, dust collectors, conveyors, $MgSO_3$ storage hopper, and loading system)	1,228,000
Magnesium oxide slurrying (MgO unloading and storage facilities, feeders, conveyors, elevators, slurry tank, agitator, and pumps)	494,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	165,000
Control room building, including motor controls, laboratory, and lockers	170,000
Service facilities and buildings allocation for maintenance, shops, and offices	610,000
Subtotal direct investment	15,417,000
Engineering design and supervision	925,000
Construction expense	1,233,000
Contractor fees	617,000
Contingency	1,696,000
Subtotal fixed capital investment	19,888,000
Allowance for startup and modifications	1,989,000
Interest during construction (8%/annum rate)	796,000
Total fixed capital investment	22,673,000

[a] Basis:

Stack gas reheat to 175° F. by indirect steam reheat.
Direct disposal of neutalized ash slurry (15% solids) with recycle of water to fly ash scrubber.
Disposal pond distance of 1 mile.
Midwest plant location–1972 costs.
Minimum in process storage; only pumps are spared; ash pond not included.

Table A-29. Summary of Estimated Fixed Investment:[a] Scheme D--Magnesia Regeneration-Sulfuric Acid Unit Central Processing Concept

(Equivalent to 1000-mw new coal-fired power unit, 3.5% S in fuel; 26.7 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	540,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors, loading and unloading equipment)	1,666,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	4,082,000
Tail gas scrubbing (scrubber, tanks, pumps, dryer, conveyor)	525,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	294,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	164,000
Control room building, including motor controls, laboratory, and lockers	160,000
Service facilities and buildings allocation for maintenance, shops, and offices	970,000
Subtotal direct investment	8,401,000
Engineering design and supervision	504,000
Construction expense	672,000
Contractor fees	336,000
Contingency	924,000
Subtotal fixed capital investment	10,837,000
Allowance for startup and modifications	1,084,000
Interest during construction (8%/annum rate)	433,000
Total fixed capital investment	12,354,000

[a] Basis:
Tail gas recovery of 90% SO_2 and SO_3 from acid absorber, reheat to 175° F.
Midwest plant location–1972 costs.
In process storage of 72 hours.

Table A-30. Summary of Estimated Fixed Investment:[a]
Scheme D—Magnesia Regeneration-Sulfuric Acid Unit
Central Processing Concept

(Equivalent to 2000-mw new coal-fired power unit, 3.5% S in fuel; 53.3 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	820,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors, loading and unloading equipment)	2,525,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	6,631,000
Tail gas scrubbing (scrubber, tanks, pumps, dryer, conveyor)	853,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	478,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	266,000
Control room building, including motor controls, laboratory, and lockers	240,000
Service facilities and buildings allocation for maintenance, shops, and offices	1,470,000
Subtotal direct investment	13,283,000
Engineering design and supervision	797,000
Construction expense	1,063,000
Contractor fees	531,000
Contingency	1,461,000
Subtotal fixed capital investment	17,135,000
Allowance for startup and modifications	1,714,000
Interest during construction (8%/annum rate)	685 000
Total fixed capital investment	19,534,000

[a] Basis:
Tail gas recovery of 90% SO_2 and SO_3 from acid absorber, reheat to 175°F.
Midwest plant location—1972 costs.
In process storage of 72 hours.

Table A-31. Summary of Estimated Fixed Investment:[a] Scheme D—Magnesia Regeneration-Sulfuric Acid Unit Central Processing Concept

(Equivalent to 3000-mw new coal-fired power unit, 3.5% S in fuel; 80.0 tons/hr H_2SO_4)

	Investment, $
Land, site clearance, excavation, landscaping, roads, railways, walkways	1,040,000
Calcining (fluid bed calcining system, fans, MgO and coke storage hoppers, feeders, conveyors, elevators, waste heat boiler, dust collectors, loading and unloading equipment)	3,221,000
Sulfuric acid plant (complete contact unit for sulfuric acid production, dry gas purification system)	9,172,000
Tail gas scrubbing (scrubber, tanks, pumps, dryer, conveyor)	1,133,000
Sulfuric acid storage (storage and shipping facilities for 30 days production of H_2SO_4)	634,000
Fuel oil storage (fuel oil storage and distribution system including storage tank, hold tanks, heat exchanger, transfer and feed pumps)	354,000
Control room building, including motor controls, laboratory, and lockers	310,000
Service facilities and buildings allocation for maintenance, shops, and offices	1,880,000
Subtotal direct investment	17,744,000
Engineering design and supervision	1,065,000
Construction expense	1,420,000
Contractor fees	710,000
Contingency	1,952,000
Subtotal fixed capital investment	22,891,000
Allowance for startup and modifications	2,289,000
Interest during construction (8%/annum rate)	916,000
Total fixed capital investment	26,096,000

[a] Basis:
Tail gas recovery of 90% SO_2 and SO_3 from acid absorber, reheat to 175°F.
Midwest plant location—1972 costs.
In process storage of 72 hours.

Table A-32. Summary of Estimated Fixed Investment Requirements: Limestone Wet-Scrubbing[a]

(500-mw new coal-fired power unit, 3.5% S in fuel)

	Investment, $
Yard improvements	
Road and general yard modifications	375,000
Limestone storage and handling facilities	236,000
Wet grinding ball mill and classifier	298,000
Slurry storage and pumping	81,000
Scrubber (four 3-stage wet scrubbers with pumps, piping, foundations, structures, and hold tank)	4,996,000
Duct work, dampers, and insulation	1,430,000
Optional by-pass duct	400,000
Solids disposal system	
Equipment and piping	395,000
Disposal pond and land	1,737,000
Stack gas reheat system	225,000
Central control room and equipment	444,000
Electrical	767,000
Buildings	220,000
Service facilities	500,000
Subtotal direct cost	12,104,000
Engineering design and supervision	605,000
Construction expense	1,089,000
Contractor fees	484,000
Contingency	1,452,000
Total fixed capital investment	15,734,000
Allowance for start-up and modification	1,259,000
Interest during construction (8%/annum rate)	629,000
Total fixed capital investment	17,622,000

[a] Basis:
Stack gas reheat to 175° F. by indirect steam method.
Direct on-site solids disposal as 10% slurry.
Scrubber-to-pond distance of 1 mi., closed loop water recycle.
Midwest plant location–1972 costs.

Table A-33. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a] Scheme A—Magnesia Slurry Scrubbing-Regeneration

(200-mw new coal-fired power unit, 3.5% S in fuel; 45,200 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Lime	54.8 tons	16.00/ton	900	.020
Magnesium oxide (98%)	448 tons	102.40/ton	45,900	1.015
Coke	312 tons	23.50/ton	7,300	.162
Catalyst	736 liters	1.51/liter	1,100	.024
Subtotal raw material			55,200	1.221
Conversion costs				
Operating labor and supervision	30,440 man-hr	6.00/man-hr	182,600	4.040
Utilities				
Fuel oil	2,190,000 gal	0.09/gal	197,100	4.361
Steam	180,000 M lb	0.60/M lb[b]	108,000	2.389
Heat credit	8,300 MM Btu	-0.40/MM Btu	(3,300)	(.073)
Process water	902,700 M gal	0.05/M gal[b]	45,100	.998
Electricity	27,300,000 kwh	0.007/kwh[b]	191,100	4.228
Maintenance				
Labor and material .07 x 11,685,000			817,900	18.095
Analyses			45,000	.995
Subtotal conversion costs			1,583,500	35.033
Subtotal direct costs			1,638,700	36.254
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			1,741,100	38.520
Overhead				
Plant, 20% of conversion costs			316,700	7.007
Administrative, research, and service, 11% of conversion costs			174,200	3.854
Subtotal indirect costs			2,232,000	49.381

	Cost/ton of coal burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	7.212	3,870,700	85.635

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 536,700 tons/yr–9,200 Btu/kwh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Midwest plant location–1972 costs.
Capital investment, $11,685,000; working capital, $281,300.

[b] Cost of utility supplied from power plant at full value.

Table A-34 Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(200-mw existing coal-fired power unit, 3.5% S in fuel; 46,600 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Lime	56.6 tons	16.00/ton	900	.019
Magnesium oxide (98%)	463 tons	102.40/ton	47,400	1.017
Coke	322 tons	23.50/ton	7,600	.163
Catalyst	760 liters	1.51/liter	1,100	.024
Subtotal raw material			57,000	1.223
Conversion costs				
Operating labor and supervision	30,440 man-hr	6.00/man-hr	182,600	3.919
Utilities				
Fuel oil	3,166,000 gal	0.09/gal	284,900	6.114
Steam	– M lb	0.60/M lb[b]		
Heat credit	8,600 MM Btu	-0.40/MM Btu	(3,400)	(.073)
Process water	931,400 M gal	0.05/M gal[b]	46,600	1.000
Electricity	28,190,000 kwh	0.007/kwh[b]	197,300	4.234
Maintenance				
Labor and material, .07 x 13,083,000			915,800	19.652
Analyses			45,000	.966
Subtotal conversion costs			1,668,800	35.812
Subtotal direct costs			1,725,800	37.035
Indirect Costs				
Average capital charges at 15.7% of initial fixed investment			2,054,000	44.077
Overhead				
Plant, 20% of conversion costs			333,800	7.163
Administrative, research, and service, 11% of conversion costs			183,600	3.940
Subtotal indirect costs			2,571,400	55.180

	Cost/ton of coal burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	7.754	4,297,200	92.215

[a] Basis:
Remaining life of power plant, 22 yr.
Coal burned, 554,200 tons/yr–9,500 Btu/kwh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Midwest plant location–1972 costs.
Capital investment, $13,083,000; working capital, $296,300.

[b] Cost of utility supplied from power plant at full value.

Table A-35. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]
Scheme A—Magnesia Slurry Scrubbing-Regeneration
(500-mw new coal-fired power unit, 2.0% S in fuel; 63,100 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Lime	76.6 tons	16.00/ton	1,200	.019
Magnesium oxide (98%)	620 tons	102.40/ton	63,500	1.006
Coke	436 tons	23.50/ton	10,200	.162
Catalyst	1,029 liters	1.51/liter	1,600	.025
Subtotal raw material			76,500	1.212
Conversion costs				
Operating labor and supervision	32,520 man-hr	6.00/man-hr	195,100	3.092
Utilities				
Fuel oil	3,061,000 gal	.09/gal	275,500	4.366
Steam	440,000 M lb	0.55/M lb[b]	242,000	3.836
Heat credit	11,600 MM Btu	-0.40/MM Btu	(4,600)	(.073)
Process water	1,350,000 M gal	0.04/M gal[b]	54,000	.856
Electricity	58,970,000 kwh	0.006/kwh[b]	353,800	5.607
Maintenance				
Labor and material, .06 x 18,788,000			1,127,300	17.865
Analyses			76,000	1.204
Subtotal conversion costs			2,319,100	36.753
Subtotal direct costs			2,395,600	37.965
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			2,799,400	44.365
Overhead				
Plant, 20% of conversion costs			463,800	7.350
Administrative, research, and service, 11% of conversion costs			255,100	4.043
Subtotal indirect costs			3,518,300	55.758

	Cost/ton of coal burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	4.506	5,913,900	93.723

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr—9,000 Btu/kwh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Midwest plant location—1972 costs.
Capital investment, $18,788,000; working capital, $411,200.

[b] Cost of utility supplied from power plant at full value.

Table A-36. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(500-mw new coal-fired power unit, 3.5% S in fuel; 110,400 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Lime	134.1 tons	16.00/ton	2,100	.019
Magnesium oxide (98%)	1,086 tons	102.40/ton	111,200	1.007
Coke	763 tons	23.50/ton	17,900	.162
Catalyst	1,800 liters	1.51/liter	2,700	.024
Subtotal raw material			133,900	1.212
Conversion costs				
Operating labor and supervision	39,200 man-hr	6.00/man-hr	235,200	2.130
Utilities				
Fuel oil	5,356,000 gal	0.09/gal	482,000	4.366
Steam	440,000 M lb	0.55/M lb[b]	242,000	2.192
Heat credit	20,300 MM Btu	-0.40/MM Btu	(8,100)	(.073)
Process water	2,207,500 M gal	0.03/M gal[b]	66,200	.600
Electricity	66,760,000 kwh	0.006/kwh[b]	400,600	3.629
Maintenance				
Labor and material, .06 x 21,732,000			1,303,900	11.811
Analyses			85,000	.770
Subtotal conversion costs			2,806,800	25.425
Subtotal direct costs			2,940,700	26.637
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			3,238,100	29.331
Overhead				
Plant, 20% of conversion costs			561,400	5.085
Administrative, research, and service, 11% of conversion costs			308,700	2.797
Subtotal indirect costs			4,108,200	37.213

	Cost/ton of coal burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	5.371	7,048,900	63.850

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr–9,000 Btu/kwh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Midwest plant location–1972 costs.
Capital investment, $21,732,000; working capital, $505,600.

[b] Cost of utility supplied from power plant at full value.

Table A-37. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a] Scheme A—Magnesia Slurry Scrubbing-Regeneration

(500-mw new coal-fired power unit, 5.0% S in fuel; 157,800 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Lime	191.5 tons	16.00/ton	3,100	.020
Magnesium oxide (98%)	1,551 tons	102.40/ton	158,800	1.006
Coke	1,090 tons	23.50/ton	25,600	.162
Catalyst	2,571 liters	1.51/liter	3,900	.025
Subtotal raw material			191,400	1.213
Conversion costs				
Operating labor and supervision	45,880 man-hr	6.00/man-hr	275,300	1.745
Utilities				
Fuel oil	7,652,000 gal	0.09/gal	688,700	4.364
Steam	440,000 M lb	0.55/M lb[b]	242,000	1.534
Heat credit	29,000 MM Btu	-0.40/MM Btu	(11,600)	(.074)
Process water	3,063,900 M gal	0.02/M gal[b]	61,300	.388
Electricity	74,550,000 kwh	0.006/kwh[b]	447,300	2.835
Maintenance				
Labor and material, .06 x 24,275,000			1,456,500	9.230
Analyses			91,000	.577
Subtotal conversion costs			3,250,500	20.599
Subtotal direct costs			3,441,900	21.812
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			3,617,000	22.921
Overhead				
Plant, 20% of conversion costs			650,100	4.120
Administrative, research, and service, 11% of conversion costs			357,600	2.266
Subtotal indirect costs			4,624,700	29.307

	Cost/ton of coal burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	6.146	8,066,600	51.119

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr–9,000 Btu/kwh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Midwest plant location–1972 costs.
Capital investment, $24,275,000; working capital, $592,500.

[b] Cost of utility supplied from power plant at full value.

Table A-38. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(500-mw existing coal-fired power unit, 3.5% S in fuel; 112,900 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Lime	137.0 tons	16.00/ton	2,200	.019
Magnesium oxide (98%)	1,110 tons	102.40/ton	113,700	1.007
Coke	780 tons	23.5/ton	18,300	.162
Catalyst	1,840 liters	1.51/liter	2,800	.025
Subtotal raw material			137,000	1.213
Conversion costs				
Operating labor and supervision	39,200 man-hr	6.00/man-hr	235,200	2.083
Utilities				
Fuel oil	7,665,000 gal	0.09/gal	689,900	6.111
Steam	– M lb	0.55/M lb[b]	–	–
Heat credit	20,800 MM Btu	-0.40/MM Btu	(8,300)	(.073)
Process water	2,256,100 M gal	0.04/M gal[b]	90,200	.799
Electricity	68,240,000 kwh	0.006/kwh[b]	409,400	3.626
Maintenance				
Labor and material, .06 x 24,646,000			1,478,800	13.098
Analyses			85,000	.753
Subtotal conversion costs			2,980,200	26.397
Subtotal direct costs			3,117,200	27.610
Indirect Costs				
Average capital charges at 15.1% of initial fixed investment			3,721,500	32.963
Overhead				
Plant, 20% of conversion costs			596,000	5.279
Administrative, research, and service, 11% of conversion costs			327,800	2.904
Subtotal indirect costs			4,645,300	41.146

	Cost/ton of coal burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	5.786	7,762,500	68.756

[a] Basis:
Remaining life of power plant, 27 yr.
Coal burned, 1,341,700 tons/yr–9,200 Btu/kwh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Midwest plant location–1972 costs.
Capital investment, $24,646,000; working capital, $535,800.

[b] Cost of utility supplied from power plant at full value.

Table A-39. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(1000-mw new coal-fired power unit, 3.5% S in fuel; 213,500 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Lime	259.2 tons	16.00/ton	4,100	.019
Magnesium oxide (98%)	2,078 tons	102.40/ton	212,800	.997
Coke	1,475 tons	23.50/ton	34,700	.162
Catalyst	3,480 liters	1.51/liter	5,300	.025
Subtotal raw material			256,900	1.203
Conversion costs				
Operating labor and supervision	47,960 man-hr	6.00/man-hr	287,800	1.348
Utilities				
Fuel oil	10,356,000 gal	0.09/gal	932,000	4.365
Steam	850,000 M lb	0.50/M lb[b]	425,000	1.990
Heat credit	39,300 MM Btu	-0.40/MM Btu	(15,700)	(.074)
Process water	4,267,000 M gal	0.02/M gal[b]	85,300	.400
Electricity	129,070,000 kwh	0.005/kwh[b]	645,400	3.023
Maintenance				
Labor and material,	.05 x 33,118,000		1,655,900	7.756
Analyses			140,000	.656
Subtotal conversion costs			4,155,700	19.464
Subtotal direct costs			4,412,600	20.667
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			4,934,600	23.113
Overhead				
Plant, 20% of conversion costs			831,100	3.894
Administrative, research, and service, 11% of conversion costs			457,100	2.141
Subtotal indirect costs			6,222,800	29.148

	Cost/ton of coal burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	4.191	10,635,400	49.815

[a] **Basis:**
Remaining life of power plant, 30 yr.
Coal burned, 2,537,500 tons/yr–8,700 Btu/kwh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Midwest plant location–1972 costs.
Capital investment, $33,118,000; working capital, $759,900.

[b] **Cost of utility supplied from power plant at full value.**

Table A-40. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(1000-mw existing coal-fired power unit, 3.5% S in fuel; 220,900 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Lime	268.1 tons	16.00/ton	4,300	.019
Magnesium oxide (98%)	2,150 tons	102.40/ton	220,200	.997
Coke	1,526 tons	23.50/ton	35,900	.163
Catalyst	3,600 liters	1.51/liter	5,400	.024
Subtotal raw material			265,800	1.203
Conversion costs				
Operating labor and supervision	47,960 man-hr	6.00/man-hr	287,800	1.303
Utilities				
Fuel oil	14,998,000 gal	0.09/gal	1,349,800	6.110
Steam	– M lb	0.50/M lb[b]	–	–
Heat credit	40,600 MM Btu	-0.40/MM Btu	(16,200)	(.073)
Process water	4,413,900 M gal	0.02/M gal[b]	88,300	.400
Electricity	133,520,000 kwh	0.005/kwh[b]	667,600	3.022
Maintenance				
Labor and material, .05 x 36,634,000			1,831,700	8.292
Analyses			140,000	.634
Subtotal conversion costs			4,349,000	19.688
Subtotal direct costs			4,614,800	20.891
Indirect Costs				
Average capital charges at 15.1% of initial fixed investment			5,531,700	25.042
Overhead				
Plant, 20% of conversion costs			869,800	3.937
Administrative, research, and service, 11% of conversion costs			478,400	2.166
Subtotal indirect costs			6,879,900	31.145

	Cost/ton of coal burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	4.379	11,494,700	52.036

[a] Basis:
Remaining life of power plant, 27 yr.
Coal burned, 2,625,000 tons/yr–9,000 Btu/kwh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Midwest plant location–1972 costs.
Capital investment, $36,634,000; working capital, $794,600.

[b] Cost of utility supplied from power plant at full value.

Table A-41. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(200-mw new oil-fired power unit, 2.5% S in fuel; 24,100 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	239 tons	102.40/ton	24,500	1.017
Coke	166 tons	23.50/ton	3,900	.162
Catalyst	393 liters	1.51/liter	600	.025
Subtotal raw material			29,000	1.204
Conversion costs				
Operating labor and supervision	28,360 man-hr	6.00/man-hr	1700,200	7.062
Utilities				
Fuel oil	2,103,000 gal	0.09/gal	189,300	7.855
Heat credit	4,430 MM Btu	-0.40/MM Btu	(1,800)	(.075)
Process water	508,000 M gal	0.07/M gal[b]	35,600	1.477
Electricity	12,190,000 kwh	0.007/kwh[b]	85,300	3.539
Maintenance				
Labor and material, .07 x 6,690,000			468,300	19.432
Analyses			30,000	1.245
Subtotal conversion costs			976,900	40.535
Subtotal direct costs			1,005,900	41.739
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			996,800	41.361
Overhead				
Plant, 20% of conversion costs			195,400	8.108
Administrative, research, and service, 11% of conversion costs			107,500	4.461
Subtotal indirect costs			1,299,700	53.930

	Cost/BBL of fuel oil burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	1.120	2,305,600	95,669

[a] Basis:
Remaining life of power plant, 30 yr.
Fuel oil burned, 2,058,200 BBL/yr–9,200 Btu/kwh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Midwest plant location–1972 costs.
Capital investment, $6,690,000; working capital, $172,600.

[b] Cost of utility supplied from power plant at full value.

Table A-42. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(500-mw new oil-fired power unit, 1.0% S in fuel; 23,600 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	232 tons	102.40/ton	23,800	1.009
Coke	163 tons	23.50/ton	3,800	.161
Catalyst	394 liters	1.51/liter	600	.025
Subtotal raw material			28,200	1.195
Conversion costs				
Operating labor and supervision	30,440 man-hr	6.00/man-hr	182,600	7.737
Utilities				
Fuel oil	3,313,000 gal	0.09/gal	298,200	12.636
Heat credit	4,330 MM Btu	-0.40/MM Btu	(1,700)	(.072)
Process water	601,800 M gal	0.06/M gal[b]	36,100	1.530
Electricity	23,990,000 kwh	0.006/kwh[b]	143,900	6.097
Maintenance				
Labor and material, .06 x 9,888,000			593,300	25.140
Analyses			55,000	2.330
Subtotal conversion costs			1,307,400	55.398
Subtotal direct costs			1,335,600	56.593
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			1,473,300	62.428
Overhead				
Plant, 20% of conversion costs			261,500	11.081
Administrative, research, and service, 11% of conversion costs			143,800	6.093
Subtotal indirect costs			1,878,600	79.602

	Cost/BBL of fuel oil burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	0.639	3,214,200	136.195

[a] Basis:
Remaining life of power plant, 30 yr.
Fuel oil burned, 5,033,600 BBL/yr–9,000 Btu/kwh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Midwest plant location–1972 costs.
Capital investment, $9,888,000; working capital, $228,900.

[b] Cost of utility supplied from power plant at full value.

Table A-43. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a] Scheme A—Magnesia Slurry Scrubbing-Regeneration

(500-mw new oil-fired power unit, 2.5% S in fuel; 58,900 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	579 tons	102.40/ton	59,300	1.007
Coke	407 tons	23.50/ton	9,600	.163
Catalyst	960 liters	1.51/liter	1,400	.024
Subtotal raw material			70,300	1.194
Conversion costs				
Operating labor and supervision	32,520 man-hr	6.00/man-hr	195,100	3.312
Utilities				
Fuel oil	5,142,000 gal	0.09/gal	462,800	7.857
Heat credit	10,830 MM Btu	-0.40/MM Btu	(4,300)	(.073)
Process water	1,241,100 M gal	0.05/M gal[b]	62,100	1.054
Electricity	29,810,000 kwh	0.006/kwh[b]	178,900	3.037
Maintenance				
Labor and material, .06 x 12,439,000			746,300	12.671
Analyses			66,000	1.121
Subtotal conversion costs			1,706,900	28.979
Subtotal direct costs			1,777,200	30.173
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			1,853,400	31.467
Overhead				
Plant, 20% of conversion costs			341,400	5.797
Administrative, research, and service, 11% of conversion costs			187,800	3.188
Subtotal indirect costs			2,382,600	40.452

	Cost/BBL of fuel oil burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	0.826	4,159,800	70.625

[a] Basis:

Remaining life of power plant, 30 yr.

Fuel oil burned, 5,033,600 BBL/yr—9,000 Btu/kwh.

Stack gas reheat to 175 F.

Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.

Midwest plant location—1972 costs.

Capital investment, $12,439,000; working capital, $305,300.

[b] Cost of utility supplied from power plant at full value.

Table A-44. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(500-mw new oil-fired power unit, 4.0% S in fuel; 94,200 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	926 tons	102.40/ton	94,800	1.006
Coke	651 tons	23.50/ton	15,300	.162
Catalyst	1,536 liters	1.51/liter	2,300	.024
Subtotal raw material			112,400	1.192
Conversion costs				
Operating labor and supervision	34,600 man-hr	6.00/man-hr	207,600	2.204
Utilities				
Fuel oil	6,856,000 gal	0.09/gal	617,000	6.550
Heat credit	17,330 MM Btu	-0.40/MM Btu	(6,900)	(0.073)
Process water	1,880,400 M gal	0.04/M gal[b]	75,200	0.798
Electricity	35,630,000 kwh	0.006/kwh[b]	213,800	2.270
Maintenance				
Labor and material, .06 x 14,568,000			874,100	9.279
Analyses			73,000	0.775
Subtotal conversion costs			2,053,800	21.803
Subtotal direct costs			2,166,200	22.995
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			2,170,600	23.043
Overhead				
Plant, 20% of conversion costs			410,800	4.361
Administrative, research, and service, 11% of conversion costs			225,900	2.398
Subtotal indirect costs			2,807,300	29.802

	Cost/BBL of fuel oil burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	0.988	4,973,500	52.797

[a] Basis:
Remaining life of power plant, 30 yr.
Fuel oil burned, 5,033,600 BBL/yr—9,000 Btu/kwh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Midwest plant location—1972 costs.
Capital investment, $14,568,000; working capital, $372,700.

[b] Cost of utility supplied from power plant at full value.

Table A-45. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(500-mw existing oil-fired power unit, 2.5% S in fuel; 60,200 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	592 tons	102.40/ton	60,600	1.006
Coke	416 tons	23.50/ton	9,800	.163
Catalyst	981 liters	1.51/liter	1,500	.025
Subtotal raw material			71,900	1.194
Conversion costs				
Operating labor and supervision	32,520 man-hr	6.00/man-hr	195,100	3.241
Utilities				
Fuel oil	5,256,000 gal	0.09/gal	473,000	7.857
Heat credit	11,070 MM Btu	-0.40/MM Btu	(4,400)	(.073)
Process water	1,268,800 M gal	0.05/M gal[b]	63,400	1.053
Electricity	30,450,000 kwh	0.006/kwh[b]	182,700	3.035
Maintenance				
Labor and material, .06 x 13,920,000			835,200	13.874
Analyses			68,000	1.130
Subtotal conversion costs			1,813,000	30.117
Subtotal direct costs			1,884,900	31.311
Indirect Costs				
Average capital charges at 15.1% of initial fixed investment			2,101,900	34.915
Overhead				
Plant, 20% of conversion costs			362,600	6.023
Administrative, research, and service, 11% of conversion costs			199,400	3.312
Subtotal indirect costs			2,663,900	44.250

	Cost/BBL of fuel oil burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	0.884	4,548,800	75.561

[a] Basis:
Remaining life of power plant, 27 yr.
Fuel oil burned, 5,145,400 BBL/yr–9,200 Btu/kwh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Midwest plant location–1972 costs.
Capital investment, $13,920,000; working capital, $323,800.

[b] Cost of utility supplied from power plant at full value.

Table A-46. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(1000-mw new oil-fired power unit, 2.5% S in fuel; 113,900 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	1,108 tons	102.40/ton	113,500	.997
Coke	787 tons	23.50/ton	18,500	.162
Catalyst	1,856 liters	1.51/liter	2,800	.025
Subtotal raw material			134,800	1.184
Conversion costs				
Operating labor and supervision	39,200 man-hr	6.00/man-hr	235,200	2.065
Utilities				
Fuel oil	9,940,000 gal	0.09/gal	894,600	7.854
Heat credit	20,940 MM Btu	-0.40/MM Btu	(8,400)	(.074)
Process water	2,399,600 M gal	0.04/M gal[b]	96,000	.843
Electricity	57,640,000 kwh	0.005/kwh[b]	288,200	2.530
Maintenance				
Labor and material, .05 x 18,888,000			944,400	8.292
Analyses			121,000	1.062
Subtotal conversion costs			2,571,000	22.572
Subtotal direct costs			2,705,800	23.756
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			2,814,300	24.709
Overhead				
Plant, 20% of conversion costs			514,200	4.514
Administrative, research, and service, 11% of conversion costs			282,800	2.483
Subtotal indirect costs			3,611,300	31.706

	Cost/BBL of fuel oil burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	0.649	6,317,100	55.462

[a] Basis:
Remaining life of power plant, 30 yr.
Fuel oil burned, 9,731,500 BBL/yr—8,700 Btu/kwh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Midwest plant location—1972 costs.
Capital investment, $18,888,000; working capital, $465,500.

[b] Cost of utility supplied from power plant at full value.

Table A-47. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme B—MgO-MnO_2 Slurry Scrubbing-Regeneration

(200-mw new coal-fired power unit, 3.5% S in fuel; 45,200 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Lime	54.8 tons	16.00/ton	900	.020
Magnesium oxide (98%)	448 tons	102.40/ton	45,900	1.015
Manganese dioxide	301 tons	90.00/ton	27,100	.600
Catalyst	736 liters	1.51/liter	1,100	.024
Subtotal raw material			75,000	1.659
Conversion costs				
Operating labor and supervision	30,440 man-hr	6.00/man-hr	182,600	4.040
Utilities				
Fuel oil	2,374,000 gal	0.09/gal	213,700	4.728
Steam	180,000 M lb	0.60/ M lb[b]	108,000	2.389
Heat credit	40,100 MM Btu	-0.40/MM Btu	(16,000)	(.354)
Process water	903,000 M gal	0.05/M gal[b]	45,200	1.000
Electricity	24,070,000 kwh	0.007/kwh[b]	168,500	3.728
Maintenance				
Labor and material, .07 x 11,990,000			839,300	18.569
Analyses			45,000	.995
Subtotal conversion costs			1,586,300	35.095
Subtotal direct costs			1,661,300	36.754
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			1,786,500	39.524
Overhead				
Plant, 20% of conversion costs			317,300	7.020
Administrative, research, and service, 11% of conversion costs			174,500	3.861
Subtotal indirect costs			2,278,300	50.405

	Cost/ton of coal burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	7.340	3,939,600	87.159

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 536,700 tons/yr 9,200 Btu/kwh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Midwest plant location—1972 costs.
Capital investment, $11,990,000; working capital, $285,600.

[b] Cost of utility supplied from power plant at full value.

Table A-48. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme B—MgO-MnO_2 Slurry Scrubbing-Regeneration

(500-mw new coal-fired power unit, 3.5% S in fuel; 110,400 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Lime	134.1 tons	16.00/ton	2,100	.019
Magnesium oxide (98%)	1,086 tons	102.40/ton	111,200	1.007
Manganese dioxide	724 tons	90.00/ton	65,200	.591
Catalyst	1,798 liters	1.51/liter	2,700	.024
Subtotal raw material			181,200	1.641
Conversion costs				
Operating labor and supervision	39,200 man-hr	6.00/man-hr	235,200	2.130
Utilities				
Fuel oil	5,806,000 gal	0.09/gal	522,500	4.733
Steam	440,000 M lb	0.55/M lb[b]	242,000	2.192
Heat credit	98,000 MM Btu	0.40/MM Btu	(39,200)	(.355)
Process water	2,207,000 M gal	0.03/M gal[b]	66,200	.600
Electricity	58,870,000 kwh	0.006/kwh[b]	353,200	3.199
Maintenance				
Labor and material, .06 x 22,237,000			1,334,200	12.085
Analyses			85,000	.770
Subtotal conversion costs			2,799,100	25.354
Subtotal direct costs			2,980,300	26.995
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			3,313,300	30.012
Overhead				
Plant, 20% of conversion costs			559,800	5.071
Administrative, research, and service, 11% of conversion costs			307,900	2.789
Subtotal indirect costs			4,181,000	37.872

	Cost/ton of coal burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	5.456	7,161,300	64.867

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 1,312,[illegible]00 tons/yr–9,000 Btu/kwh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Midwest plant location–1972 costs.
Capital investment, $22,237,000; working capital, $513,400.

[b] Cost of utility supplied from power plant at full value.

Table A-49. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme B—MgO-MnO_2 Slurry Scrubbing-Regeneration

(1000-mw new coal-fired power unit, 3.5% S in fuel; 213,500 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Lime	259.2 tons	16.00/ton	4,100	.019
Magnesium oxide (98%)	2,078 tons	102.40/ton	212,800	.997
Manganese dioxide	1,385 tons	90.00/ton	124,700	.584
Catalyst	3,477 liters	1.51/liter	5,300	.025
Subtotal raw material			346,900	1.625
Conversion costs				
Operating labor and supervision	47,960 man-hr	6.00/man-hr	287,800	1.348
Utilities				
Fuel oil	11,225,000 gal	0.09/gal	1,010,300	4.732
Steam	850,000 M lb	0.50/M lb[b]	425,000	1.991
Heat credit	189,500 MM Btu	-0.40/MM Btu	(75,800)	(.355)
Process water	4,266,000 M gal	0.02/M gal[b]	85,300	.399
Electricity	113,810,000 kwh	0.005/kwh[b]	569,100	2.665
Maintenance				
Labor and material, .05 x 33,838,000			1,691,900	7.925
Analyses			140,000	.656
Subtotal conversion costs			4,133,600	19.361
Subtotal direct costs			4,480,500	20.986
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			5,041,900	23.615
Overhead				
Plant, 20% of conversion costs			826,700	3.872
Administrative, research, and service, 11% of conversion costs			454,700	2.130
Subtotal indirect costs			6,323,300	29.617

	Cost/ton of coal burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	4.258	10,803,800	50.603

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 2,537,500 tons/yr–8,700 Btu/kwh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Midwest plant location–1972 costs.
Capital investment, $33,838,000; working capital, $773,400.

[b] Cost of utility supplied from power plant at full value.

Table A-50. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme B—MgO-MnO_2 Slurry Scrubbing-Regeneration

(200-mw new oil-fired power unit, 2.5% S in fuel; 24,100 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	239 tons	102.40/ton	24,500	1.017
Manganese dioxide	159 tons	90.00/ton	14,300	.593
Catalyst	393 liters	1.51/liter	600	.025
Subtotal raw material			39,400	1.635
Conversion costs				
Operating labor and supervision	28,360 man-hr	6.00/man-hr	170,200	7.062
Utilities				
Fuel oil	1,821,000 gal	0.09/gal	163,900	6.801
Heat credit	21,400 MM Btu	-0.40/MM Btu	(8,600)	(.357)
Process water	498,000 M gal	0.07/M gal[b]	34,900	1.448
Electricity	9,320,000 kwh	0.007/kwh[b]	65,200	2.705
Maintenance				
Labor and material, .07 x 6,806,000			476,400	19.768
Analyses			30,000	1.245
Subtotal conversion costs			932,000	38.672
Subtotal direct costs			971,400	40.307
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			1,014,100	42.079
Overhead				
Plant, 20% of conversion costs			186,400	7.734
Administrative, research, and service, 11% of conversion costs			102,500	4.253
Subtotal indirect costs			1,303,000	54.066

	Cost/BBL of fuel oil burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	1.105	2,274,400	94.373

[a] Basis:
Remaining life of power plant, 30 yr.
Fuel oil burned, 2,058,200 BBL/yr–9,200 Btu/kwh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Midwest plant location–1972 costs.
Capital investment, $6,806,000; working capital, $169,000.

[b] Cost of utility supplied from power plant at full value.

Table A-51. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a] Scheme B—MgO-MnO_2 Slurry Scrubbing-Regeneration

(500-mw new oil-fired power unit, 2.5% S in fuel; 58,900 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	579 tons	102.40/ton	59,300	1.007
Manganese dioxide	386 tons	90.00/ton	34,700	.589
Catalyst	959 liters	1.51/liter	1,400	.024
Subtotal raw material			95,400	1.620
Conversion costs				
Operating labor and supervision	32,520 man-hr	6.00/man-hr	195,100	3.312
Utilities				
Fuel oil	4,454,000 gal	0.09/gal	400,900	6.807
Heat credit	52,300 MM Btu	-0.40/MM Btu	(20,900)	(.355)
Process water	1,217,000 M gal	0.05/M gal[b]	60,900	1.034
Electricity	22,780,000 kwh	0.006/kwh[b]	136,700	2.321
Maintenance				
Labor and material, .06 x 12,561,000			753,700	12.796
Analyses			66,000	1.120
Subtotal conversion costs			1,592,400	27.035
Subtotal direct costs			1,687,800	28.655
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			1,871,600	31.776
Overhead				
Plant, 20% of conversion costs			318,500	5.407
Administrative, research, and service, 11% of conversion costs			175,200	2.975
Subtotal indirect costs			2,365,300	40.158

	Cost/BBL of fuel oil burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	.805	4,053,100	68.813

[a] Basis:
Remaining life of power plant, 30 yr.
Fuel oil burned, 5,033,600 BBL/yr—9,000 Btu/kwh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Midwest plant location—1972 costs.
Capital investment, $12,561,000; working capital, $294,800.

[b] Cost of utility supplied from power plant at full value.

Table A-52. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme B—MgO-MnO_2 Slurry Scrubbing-Regeneration

(1000-mw new oil-fired power unit, 2.5% S in fuel; 113,900 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	1,108 tons	102.40/ton	113,500	.996
Manganese dioxide	739 tons	90.00/ton	66,500	.584
Catalyst	1,855 liters	1.51/liter	2,800	.025
Subtotal raw material			182,800	1.605
Conversion costs				
Operating labor and supervision	39,200 man-hr	6.00/man-hr	235,200	2.065
Utilities				
Fuel oil	8,611,000 gal	0.09/gal	775,000	6.805
Heat credit	101,000 MM Btu	-0.40/MM Btu	(40,400)	(.355)
Process water	2,352,000 M gal	0.04/M gal[b]	94,100	.826
Electricity	44,050,000 kwh	0.005/kwh[b]	220,300	1.934
Maintenance				
Labor and material, .05 x 19,126,000			956,300	8.396
Analyses			121,000	1.062
Subtotal conversion costs			2,361,500	20.733
Subtotal direct costs			2,544,300	22.338
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			2,849,800	25.020
Overhead				
Plant, 20% of conversion costs			472,300	4.147
Administrative, research, and service, 11% of conversion costs			259,800	2.281
Subtotal indirect costs			3,581,900	31.448

	Cost/BBL of fuel oil burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	.630	6,126,200	53.786

[a] Basis:

Remaining life of power plant, 30 yr.

Fuel oil burned, 9,731,500 BBL/yr–8,700 Btu/kwh.

Stack gas reheat to 175° F.

Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.

Midwest plant location–1972 costs.

Capital investment, $19,126,000; working capital, $445,700.

[b] Cost of utility supplied from power plant at full value.

Table A-53. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a] Scheme C—Magnesia Clear Liquor Scrubbing-Regeneration

(200-mw new coal-fired power unit, 3.5% S in fuel; 38,700 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	373 tons	102.40/ton	38,200	.987
Coke	130 tons	23.50/ton	3,100	.080
Catalyst	630 liters	1.51/liter	1,000	.026
Subtotal raw material			42,300	1.093
Conversion costs				
Operating labor and supervision	30,440 man-hr	6.00/man-hr	182,600	4.718
Utilities				
Fuel oil	1,836,000 gal	0.09/gal	165,200	4.269
Steam	247,000 M lb	0.60/M lb[b]	148,200	3.829
Heat credit	40,400 MM Btu	-0.40/MM Btu	(16,200)	(.419)
Process water	837,300 M gal	0.05/M gal[b]	41,900	1.082
Electricity	24,583,000 kwh	.007/kwh[b]	172,100	4.447
Maintenance				
Labor and material, .07 x 9,923,000			694,600	17.948
Analyses			38,000	.982
Subtotal conversion costs			1,426,400	36.858
Subtotal direct costs			1,468,700	37.951
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			1,478,500	38.204
Overhead				
Plant, 20% of conversion costs			285,300	7.372
Administrative, research, and service, 11% of conversion costs			156,900	4.054
Subtotal indirect costs			1,920,700	49.630

	Cost/ton of coal burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	6.315	3,389,400	87.581

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 536,700 tons/yr–9,200 Btu/kwh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Midwest plant location–1972 costs.
Capital investment, $9,923,000; working capital, $252,000.

[b] Cost of utility supplied from power plant at full value.

Table A-54. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]
Scheme C—Magnesia Clear Liquor Scrubbing-Regeneration

(500-mw new coal-fired power unit, 3.5% S in fuel; 94,700 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	911 tons	102.40/ton	93,300	.986
Coke	319 tons	23.50/ton	7,500	.079
Catalyst	1,542 liters	1.51/liter	2,300	.024
Subtotal raw material			103,100	1.089
Conversion costs				
Operating labor and supervision	39,200 man-hr	6.00/man-hr	235,200	2.484
Utilities				
Fuel oil	4,490,000 gal	0.09/gal	404,100	4.267
Steam	604,000 M lb	0.55/M lb[b]	332,200	3.508
Heat credit	98,700 MM Btu	-0.40/MM Btu	(39,500)	(.417)
Process water	2,048,800 M gal	0.03/M gal[b]	61,500	.649
Electricity	60,119,000 kwh	0.006/kwh[b]	360,700	3.809
Maintenance				
Labor and material, .06 x 18,111.000			1,086,700	11.475
Analyses			73,000	.771
Subtotal conversion costs			2,513,900	26.546
Subtotal direct costs			2,617,000	27.635
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			2,698,500	28.495
Overhead				
Plant, 20% of conversion costs			502,800	5.309
Administrative, research, and service, 11% of conversion costs			276,500	2.920
Subtotal indirect costs			3,477,800	36.724

	Cost/ton of coal burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	4.644	6,094,800	64.359

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr–9,000 Btu/kwh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Midwest plant location–1972 costs.
Capital investment, $18,111,000; working capital, $449,600.

[b] Cost of utility supplied from power plant at full value.

Table A-55. Regulated Company Economics—Total Venture Average Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a] Scheme C—Magnesia Clear Liquor Scrubbing-Regeneration

(1000-mw new coal-fired power unit, 3.5% S in fuel; 183,000 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	1,761 tons	102.40/ton	180,300	.985
Coke	617 tons	23.50/ton	14,500	.079
Catalyst	2,980 liters	1.51/liter	4,500	.025
Subtotal raw material			199,300	1.089
Conversion costs				
Operating labor and supervision	47,960 man-hr	6.00/man-hr	287,800	1.573
Utilities				
Fuel oil	8,681,000 gal	0.09/gal	781,300	4.269
Steam	1,168,000 M lb	0.50/M lb[b]	584,000	3.191
Heat credit	190,800 MM Btu	-0.40/MM Btu	(76,300)	(.417)
Process water	3,961,500 M gal	0.02/M gal[b]	79,200	.433
Electricity	116,228,000 kwh	0.005/kwh[b]	581,100	3.175
Maintenance				
Labor and material, .05 x 27,540,000			1,377,000	7.525
Analyses			119,000	.650
Subtotal conversion costs			3,733,100	20.399
Subtotal direct costs			3,932,400	21.488
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			4,103,500	22.423
Overhead				
Plant, 20% of conversion costs			746,600	4.080
Administrative, research, and service, 11% of conversion costs			410,600	2.244
Subtotal indirect costs			5,260,700	28.747

	Cost/ton of coal burned, $	Total annual cost, $	Cost/ton of acid, $
Total annual manufacturing costs for H_2SO_4	3.623	9,193,100	50.235

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 2,537,500 tons/yr–8,700 Btu/kwh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Midwest plant location–1972 costs.
Capital investment, $27,540,000; working capital, $676,500.

[b] Cost of utility supplied from power plant at full value.

Table A-56. Regulated Company Economics—Average Annual Operating Costs for Limestone—Wet Scrubbing of Power Plant Stack Gas[a] Low Limestone Cost, On-Site Solids Disposal

(500-mw new coal-fired power unit, 3.5% S in fuel)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of coal burned, $
Direct Costs (excluding solids disposal)				
Delivered raw material				
Limestone	192.5 M tons	2.05/ton	394,600	.301
Subtotal raw material			394,600	.301
Conversion costs				
Operating labor and supervision	23,280 man-hr	6.00/man-hr	139,700	.106
Utilities				
Steam	379,000 MM Btu	.50/MM Btu	189,500	.145
Process water	210,000 M gal	.07/M gal[b]	14,700	.011
Electricity	56,420,000 kwh	0.006/kwh[b]	338,500	.258
Maintenance				
Labor and material, .08 x 14,364,000			1,149,100	.875
Analyses			38,000	.029
Subtotal conversion costs			1,869,500	1.424
Subtotal direct costs			2,264,100	1.725
Indirect Costs (excluding solids disposal)				
Average capital charges at 14.9% of initial fixed investment			2,140,200	1.630
Overhead				
Plant, 17.5% of conversion costs			327,000	.249
Administrative, 11% of operating labor			15,400	.012
Subtotal indirect costs			2,482,600	1.891
Total annual operating costs, excluding costs for disposal of solids			4,746,700	3.616
Annual operating costs for on-site pond disposal of solids			629,600	.480
Total annual operating costs, including disposal costs			5,376,300	4.096

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr–9,000 Btu/kwh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location–1972 costs.
Capital investment, $14,364,000 plus $3,258,000 on-site solids disposal investment.
Solids disposed 234,300 tons/yr calcium solids including hydrate water
118,100 tons/yr free water
Total 352,400 tons/yr

[b] Cost of utility supplied from power plant at full value.

Table A-57. Regulated Company Economics—Average Annual Operating Costs for Limestone—Wet Scrubbing of Power Plant Stack Gas[a] High Limestone Cost, Off-site Solids Disposal

(500-mw new coal-fired power unit, 3.5% S in fuel)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of coal burned, $
Direct Costs (excluding solids disposal)				
Delivered raw material				
Limestone	192.5 M tons	6.00/ton	1,155,000	.881
Subtotal raw material			1,155,000	.881
Conversion costs				
Operating labor and supervision	23,280 man-hr	6.00/man-hr	139,700	.106
Utilities				
Steam	379,000 MM Btu	.50/MM Btu	189,500	.145
Process water	210,000 M gal	.07/M gal[b]	14,700	.011
Electricity	56,420,000 kwh	0.006/kwh[b]	338,500	.258
Maintenance				
Labor and material, .08 x 14,364,000			1,149,100	.875
Analyses			38,000	.029
Subtotal conversion costs			1,869,500	1.424
Subtotal direct costs			3,024,500	2.305
Indirect Costs (excluding solids disposal)				
Average capital charges at 14.9% of initial fixed investment			2,140,200	1.630
Overhead				
Plant, 17.5% of conversion costs			327,000	.249
Administrative, 11% of operating labor			15,400	.012
Subtotal indirect costs			2,482,600	1.891
Total annual operating costs, excluding costs for disposal of solids			5,507,100	4.196
Annual operating costs for off-site disposal of solids at $6/ton			2,114,400	1.611
Total annual operating costs, including disposal costs			7,621,500	5.807

[a] Basis:

Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr–9,000 Btu/kwh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location–1972 costs.
Capital investment, $14,364,000.

Solids disposed	234,300 tons/yr calcium solids including hydrate water
	118,100 tons/yr free water
Total	352,400 tons/yr

[b] Cost of utility supplied from power plant at full value.

Table A-58. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(200-mw new coal-fired power unit, 3.5% S in fuel; 45,200 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Lime	54.8 tons	16.00/ton	900	.020
Magnesium oxide (98%)	448 tons	102.40/ton	45,900	1.015
Coke	312 tons	23.50/ton	7,300	.162
Catalyst	736 liters	1.51/liter	1,100	.024
Subtotal raw material			55,200	1.221
Conversion costs				
Operating labor and supervision	30,440 man-hr	6.00/man-hr	182,600	4.040
Utilities				
Fuel oil	2,190,000 gal	0.09/gal	197,100	4.361
Steam	180,000 M lb	0.60/M lb[b]	108,000	2.389
Heat credit	8,300 MM Btu	-0.40/MM Btu	(3,300)	(.073)
Process water	902,700 M gal	0.05/M gal[b]	45,100	.998
Electricity	27,300,000 kwh	0.007/kwh[b]	191,100	4.228
Maintenance				
Labor and material, .07 x 11,685,000			817,900	18.095
Analyses			45,000	.995
Subtotal conversion costs			1,583,500	35.033
Subtotal direct costs			1,638,700	36.254
Indirect Costs				
Depreciation at 10% of fixed investment			1,168,500	25.852
Local taxes and insurance at 2% of fixed investment			233,700	5.170
Overhead				
Plant, 20% of conversion costs			316,700	7.007
Administrative, research, and service, 7% of conversion costs			110,800	2.451
Subtotal indirect costs			1,829,700	40.480
Total annual manufacturing costs for H_2SO_4			3,468,400	76.734

[a] Basis:
Coal burned, 536,700 tons/yr–9,200 Btu/kwh.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Stack gas reheat to 175°F.
Midwest plant location–1972 costs.
Capital investment, $11,685,000; working capital, $281,300

[b] Cost of utility supplied from power plant at full value.

Table A-59. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(200-mw existing coal-fired power unit, 3.5% S in fuel; 46,600 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Lime	56.6 tons	16.00/ton	900	.019
Magnesium oxide (98%)	463 tons	102.40/ton	47,400	1.017
Coke	322 tons	23.50/ton	7,600	.163
Catalyst	760 liters	1.51/liter	1,100	.024
Subtotal raw material			57,000	1.223
Conversion costs				
Operating labor and supervision	30,440 man-hr	6.00/man-hr	182,600	3.919
Utilities				
Fuel oil	3,166,000 gal	0.09/gal	284,900	6.114
Steam	— M lb	0.60/M lb[b]	—	—
Heat credit	8,600 MM Btu	-0.40/MM Btu	(3,400)	(.073)
Process water	931,400 M gal	0.05/M gal[b]	46,600	1.000
Electricity	28,190,000 kwh	0.007/kwh[b]	197,300	4.234
Maintenance				
Labor and material, .07 x 13,083,000			915,800	19.652
Analyses			45,000	.966
Subtotal conversion costs			1,668,800	35.812
Subtotal direct costs			1,725,800	37.035
Indirect Costs				
Depreciation at 10% of fixed investment			1,308,300	28.075
Local taxes and insurance at 2% of fixed investment			261,700	5.616
Overhead				
Plant, 20% of conversion costs			333,800	7.163
Administrative, research, and service, 7% of conversion costs			116,800	2.506
Subtotal indirect costs			2,020,600	43.360
Total annual manufacturing costs for H_2SO_4			3,746,400	80.395

[a] Basis:
Coal burned, 554,200 tons/yr–9,500 Btu/kwh.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Stack gas reheat to 175°F.
Midwest plant location–1972 costs.
Capital investment, $13,083,000; working capital, $296,300.

[b] Cost of utility supplied from power plant at full value.

Table A-60. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(500-mw new coal-fired power unit, 2.0% S in fuel; 63,100 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Lime	76.6 tons	16.00/ton	1,200	.019
Magnesium oxide (98%)	620 tons	102.40/ton	63,500	1.006
Coke	436 tons	23.50/ton	10,200	.162
Catalyst	1,029 liters	1.51/liter	1,600	.025
Subtotal raw material			76,500	1.212
Conversion costs				
Operating labor and supervision	32,520 man-hr	6.00/man-hr	195,100	3.092
Utilities				
Fuel oil	3,061,000 gal	0.09/gal	275,500	4.366
Steam	440,000 M lb	0.55/M lb[b]	242,000	3.836
Heat credit	11,600 MM Btu	-0.40/MM Btu	(4,600)	(.073)
Process water	1,350,100 M gal	0.04/M gal[b]	54,000	.856
Electricity	58,970,000 kwh	0.006/kwh[b]	353,800	5.607
Maintenance				
Labor and material, .06 x 18,788,000			1,127,300	17.865
Analyses			76,000	1.204
Subtotal conversion costs			2,319,100	36.753
Subtotal direct costs			2,395,600	37.965
Indirect Costs				
Depreciation at 10% of fixed investment			1,878,800	29.775
Local taxes and insurance at 2% of fixed investment			375,800	5.956
Overhead				
Plant, 20% of conversion costs			463,800	7.350
Administrative, research, and service, 7% of conversion costs			162,300	2.572
Subtotal indirect costs			2,880,700	45.653
Total annual manufacturing costs for H_2SO_4			5,276,300	83.618

[a] Basis:
Coal burned, 1,312,500 tons/yr–9,000 Btu/kwh.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Stack gas reheat to 175°F.
Midwest plant location–1972 costs.
Capital investment, $18,788,000; working capital, $411,200.

[b] Cost of utility supplied from power plant at full value.

Table A-61. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(500-mw new coal-fired power unit, 3.5% S in fuel; 110,400 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Lime	134.1 tons	16.00/ton	2,100	.019
Magnesium oxide (98%)	1,086 tons	102.40/ton	111,200	1.007
Coke	763 tons	23.50/ton	17,900	.162
Catalyst	1,800 liters	1.51/liter	2,700	.024
Subtotal raw material			133,900	1.212
Conversion costs				
Operating labor and supervision	39,200 man-hr	6.00/man-hr	235,200	2.130
Utilities				
Fuel oil	5,356,000 gal	0.09/gal	482,000	4.366
Steam	440,000 M lb	0.55/M lb[b]	242,000	2.192
Heat credit	20,300 MM Btu	-0.40/MM Btu	(8,100)	(.073)
Process water	2,207,500 M gal	0.03/M gal[b]	66,200	.600
Electricity	66,760,000 kwh	0.006/kwh[b]	400,600	3.629
Maintenance				
Labor and material, .06 x 21,732,000			1,303,900	11.811
Analyses			85,000	.770
Subtotal conversion costs			2,806,800	25.425
Subtotal direct costs			2,940,700	26.637
Indirect Costs				
Depreciation at 10% of fixed investment			2,173,200	19.685
Local taxes and insurance at 2% of fixed investment			434,600	3.936
Overhead				
Plant, 20% of conversion costs			561,400	5.085
Administrative, research, and service, 7% of conversion costs			196,500	1.780
Subtotal indirect costs			3,365,700	30.486
Total annual manufacturing costs for H_2SO_4			6,306,400	57.123

[a] Basis:

Coal burned, 1,312,500 tons/yr—9,000 Btu/kwh.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Stack gas reheat to 175°F.
Midwest plant location—1972 costs.
Capital investment, $21,732,000; working capital, $505,600.

[b] Cost of utility supplied from power plant at full value.

Table A-62. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(500-mw new coal-fired power unit, 5.0% S in fuel; 157,800 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, \$	Total annual cost, \$	Cost/ton of acid, \$
Direct Costs				
Delivered raw material				
Lime	191.5 tons	16.00/ton	3,100	.020
Magnesium oxide (98%)	1,551 tons	102.40/ton	158,800	1.006
Coke	1,090 tons	23.50/ton	26,600	.162
Catalyst	2,571 liters	1.51/liter	3,900	.025
Subtotal raw material			191,400	1.213
Conversion costs				
Operating labor and supervision	45,880 man-hr	6.00/man-hr	275,300	1.745
Utilities				
Fuel oil	7,652,000 gal	0.09/gal	688,700	4.364
Steam	440,000 M lb	0.55/M lb[b]	242,000	1.534
Heat credit	29,000 MM Btu	-0.40/MM Btu	(11,600)	(.074)
Process water	3,063,900 M gal	0.02/M gal[b]	61,300	.388
Electricity	74,550,000 kwh	0.006/kwh[b]	447,300	2.835
Maintenance				
Labor and material, .06 x 24,275,000			1,456,500	9.230
Analyses			91,000	.577
Subtotal conversion costs			3,250,500	20.599
Subtotal direct costs			3,441,900	21.812
Indirect Costs				
Depreciation at 10% of fixed investment			2,427,500	15.383
Local taxes and insurance at 2% of fixed investment			485,500	3.076
Overhead				
Plant, 20% of conversion costs			650,100	4.120
Administrative, research, and service, 7% of conversion costs			650,100	4.120
Subtotal indirect costs			3,790,600	24.021
Total annual manufacturing costs for H_2SO_4			7,232,500	45.833

[a] Basis:

Coal burned, 1,312,500 tons/yr–9,000 Btu/kwh.

Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.

Stack gas reheat to 175°F.

Midwest plant location–1972 costs.

Capital investment, \$24,275,000; working capital, \$592,500.

[b] Cost of utility supplied from power plant at full value.

Table A-63. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(500-mw existing coal-fired power unit, 3.5% S in fuel; 112,900 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Lime	137.0 tons	16.00/ton	2,200	.019
Magnesium oxide (98%)	1,110 tons	102.40/ton	113,700	1.007
Coke	780 tons	23.50/ton	18,300	.162
Catalyst	1,840 liters	1.51/liter	2,800	.025
Subtotal raw material			137,000	1.213
Conversion costs				
Operating labor and supervision	39,200 man-hr	6.00/man-hr	235,200	2.083
Utilities				
Fuel oil	7,665,000 gal	0.09/gal	689,900	6.111
Steam	— M lb	0.55/M lb[b]	—	—
Heat credit	20,800 MM Btu	-0.40/MM Btu	(8,300)	(.073)
Process water	2,256,100 M gal	0.04/M gal[b]	90,200	.799
Electricity	68,240,000 kwh	0.006/kwh[b]	409,400	3.626
Maintenance				
Labor and material, .06 x 24,646,000			1,478,800	13,098
Analyses			85,000	.753
Subtotal conversion costs			2,980,200	26.397
Subtotal direct costs			3,117,200	27.610
Indirect Costs				
Depreciation at 10% of fixed investment			2,464,600	21.830
Local taxes and insurance at 2% of fixed investment			492,900	4.366
Overhead				
Plant, 20% of conversion costs			596,000	5.279
Administrative, research, and service, 7% of conversion costs			208,600	1.848
Subtotal indirect costs			3,762,100	33.323
Total annual manufacturing costs for H_2SO_4			6,879,300	60.933

[a] Basis:
Coal burned, 1,341,700 tons/yr–9,200 Btu/kwh.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Stack gas reheat to 175°F.
Midwest plant location–1972 costs.
Capital investment, $24,646,000; working capital, $535,800.

[b] Cost of utility supplied from power plant at full value.

Table A-64. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(1000-mw new coal-fired power unit, 3.5% S in fuel; 213,500 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Lime	259.2 tons	16.00/ton	4,100	.019
Magnesium oxide (98%)	2,078 tons	102.40/ton	212,800	.997
Coke	1,475 tons	23.50/ton	34,700	.162
Catalyst	3,480 liters	1.51/liter	5,300	.025
Subtotal raw material			256,900	1.203
Conversion costs				
Operating labor and supervision	47,960 man-hr	6.00/man-hr	287,800	1.348
Utilities				
Fuel oil	10,356,000 gal	0.09/gal	932,000	4.365
Steam	850,000 M lb	0.50/M lb[b]	425,000	1.990
Heat credit	39,300 MM Btu	-0.40/MM Btu	(15,700)	(.074)
Process water	4,267,000 M gal	0.02/M gal[b]	85,300	.400
Electricity	129,070,000 kwh	0.005/kwh[b]	645,400	3.023
Maintenance				
Labor and material, .05 x 33,118,000			1,655,900	7.756
Analyses			140,000	.656
Subtotal conversion costs			4,155,700	19.464
Subtotal direct costs			4,412,600	20.667
Indirect Costs				
Depreciation at 10% of fixed investment			3,311,800	15.512
Local taxes and insurance at 2% of fixed investment			662,400	3.103
Overhead				
Plant, 20% of conversion costs			831,100	3.893
Administrative, research, and service, 7% of conversion costs			290,900	1.363
Subtotal indirect costs			5,096,200	23.871
Total annual manufacturing costs for H_2SO_4			9,508,800	44.538

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[a] Basis:

Coal burned, 2,537,500 tons/yr–8,700 Btu/kwh.

Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.

Stack gas reheat to 175°F.

Midwest plant location–1972 costs.

Capital investment, $33,118,000; working capital, $759,900.

[b] Cost of utility supplied from power plant at full value.

Table A-65. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]
Scheme A—Magnesia Slurry Scrubbing-Regeneration
(1000-mw existing coal-fired power unit, 3.5% S in fuel; 220,900 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Lime	268.1 tons	16.00/ton	4,300	.019
Magnesium oxide (98%)	2,150 tons	102.40/ton	220,200	.997
Coke	1,526 tons	23.50/ton	35,900	.163
Catalyst	3,600 liters	1.51/liter	5,400	.024
Subtotal raw material			265,800	1.203
Conversion costs				
Operating labor and supervision	47,960 man-hr	6.00/man-hr	287,800	1.303
Utilities				
Fuel oil	14,998,000 gal	0.09/gal	1,349,800	6.110
Steam	– M lb	0.50/M lb[b]	–	–
Heat credit	40,600 MM Btu	-0.40/MM Btu	(16,200)	(.073)
Process water	4,413,900 M gal	0.02/M gal[b]	88,300	.400
Electricity	133,520,000 kwh	0.005/kwh[b]	667,600	3.022
Maintenance				
Labor and material, .05 x 36,634,000			1,831,700	8.292
Analyses			140,000	.634
Subtotal conversion costs			4,349,000	19.688
Subtotal direct costs			4,614,800	20.891
Indirect Costs				
Depreciation at 10% of fixed investment			3,663,400	16.584
Local taxes and insurance at 2% of fixed investment			732,700	3.317
Overhead				
Plant, 20% of conversion costs			869,800	3.937
Administrative, research, and service, 7% of conversion costs			304,400	1.378
Subtotal indirect costs			5,570,300	25.216
Total annual manufacturing costs for H_2SO_4			10,185,100	46.107

[a] Basis:
Coal burned, 2,625,000 tons/yr–9,000 Btu/kwh.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Stack gas reheat to 175°F.
Midwest plant location–1972 costs.
Capital investment, $36,634,000; working capital, $794,600.

[b] Cost of utility supplied from power plant at full value.

Table A-66. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(200-mw new oil-fired power unit, 2.5% S in fuel; 24,100 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	239 tons	102.40/ton	24,500	1.017
Coke	166 tons	23.50/ton	3,900	.162
Catalyst	393 liters	1.51/liter	600	.025
Subtotal raw material			29,000	1.204
Conversion costs				
Operating labor and supervision	28,360 man-hr	6.00/man-hr	170,200	7.062
Utilities				
Fuel oil	2,103,000 gal	0.09/gal	189,300	7.855
Heat credit	4,430 MM Btu	-0.40/MM Btu	(1,800)	(.075)
Process water	508,000 M gal	0.07/M gal[b]	35,600	1.477
Electricity	12,190,000 kwh	0.007/kwh[b]	85,300	3.539
Maintenance				
Labor and material, .07 x 6,690,000			468,300	19.432
Analyses			30,000	1.245
Subtotal conversion costs			976,900	40.535
Subtotal direct costs			1,005,900	41.739
Indirect Costs				
Depreciation at 10% of fixed investment			669,000	27.759
Local taxes and insurance at 2% of fixed investment			133,800	5.552
Overhead				
Plant, 20% of conversion costs			195,400	8.108
Administrative, research, and service, 7% of conversion costs			68,400	2.838
Subtotal indirect costs			1,066,600	44.257
Total annual manufacturing costs for H_2SO_4			2,072,500	85.996

[a] Basis:

Fuel oil burned, 2,058,200 BBL/yr–9,200 Btu/kwh.

Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.

Stack gas reheat to 175°F.

Midwest plant location–1972 costs.

Capital investment, $6,690,000; working capital, $172,600.

[b] Cost of utility supplied from power plant at full value.

Table A-67. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(500-mw new oil-fired power unit, 1.0% S in fuel; 23,600 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	232 tons	102.40/ton	23,800	1.009
Coke	163 tons	23.50/ton	3,800	.161
Catalyst	384 liters	1.51/liter	600	.025
Subtotal raw material			28,200	1.195
Conversion costs				
Operating labor and supervision	30,440 man-hr	6.00/man-hr	182,600	7.737
Utilities				
Fuel oil	3,313,000 gal	0.09/gal	298,200	12.636
Heat credit	4,330 MM Btu	-0.40/MM Btu	(1,700)	(.072)
Process water	601,800 M gal	0.06/M gal[b]	36,100	1.530
Electricity	23,990,000 kwh	0.006/kwh[b]	143,900	6.097
Maintenance				
Labor and material, .06 x 9,888,000			593,300	25.140
Analyses			55,000	2.330
Subtotal conversion costs			1,307,400	55.398
Subtotal direct costs			1,335,600	56.593
Indirect Costs				
Depreciation at 10% of fixed investment			988,800	41.898
Local taxes and insurance at 2% of fixed investment			197,800	8.382
Overhead				
Plant, 20% of conversion costs			261,500	11.081
Administrative, research, and service, 7% of conversion costs			91,500	3.877
Subtotal indirect costs			1,539,600	65.238
Total annual manufacturing costs for H_2SO_4			2,875,200	121.831

[a] Basis:
Fuel oil burned, 5,033,600 BBL/yr–9,000 Btu/kwh.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Stack gas reheat to 175°F.
Midwest plant location–1972 costs.
Capital investment, $9,888,000; working capital, $228,900.

[b] Cost of utility supplied from power plant at full value.

Table A-68. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]
Scheme A—Magnesia Slurry Scrubbing-Regeneration

(500-mw new oil-fired power unit, 2.5% S in fuel; 58,900 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	579 tons	102.40/ton	59,300	1.007
Coke	407 tons	23.50/ton	9,600	.163
Catalyst	960 liters	1.51/liter	1,400	.024
Subtotal raw material			70,300	1.194
Conversion costs				
Operating labor and supervision	32,520 man-hr	6.00/man-hr	195,100	3.312
Utilities				
Fuel oil	5,142,000 gal	0.09/gal	462,800	7.857
Heat credit	10,830 MM Btu	-0.40/MM Btu	(4,300)	(.073)
Process water	1,241,100 M gal	0.05/M gal[b]	62,100	1.054
Electricity	29,810,000 kwh	0.006/kwh[b]	178,900	3.037
Maintenance				
Labor and material, .06 x 12,439,000			746,300	12.671
Analyses			66,000	1.121
Subtotal conversion costs			1,706,900	28.979
Subtotal direct costs			1,777,200	30.173
Indirect Costs				
Depreciation at 10% of fixed investment			1,243,900	21.119
Local taxes and insurance at 2% of fixed investment			248,800	4.224
Overhead				
Plant, 20% of conversion costs			341,400	5.796
Administrative, research, and service, 7% of conversion costs			119,500	2.029
Subtotal indirect costs			1,953,600	33.168
Total annual manufacturing costs for H_2SO_4			3,730,800	63.341

[a] Basis:
Fuel oil burned, 5,033,600 BBL/yr–9,000 Btu/kwh.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Stack gas reheat to 175°F.
Midwest plant location–1972 costs.
Capital investment, $12,439,000; working capital, $305,300.

[b] Cost of utility supplied from power plant at full value.

Table A-69. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(500-mw new oil-fired power unit, 4.0% S in fuel; 94,200 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	926 tons	102.40/ton	94,800	1.006
Coke	651 tons	23.50/ton	15,300	.162
Catalyst	1,536 liters	1.51/liter	2,300	.024
Subtotal raw material			112,400	1.192
Conversion costs				
Operating labor and supervision	34,600 man-hr	6.00/man-hr	207,600	2.204
Utilities				
Fuel oil	6,856,000 gal	0.09/gal	617,000	6.550
Heat credit	17,330 MM Btu	-0.40/MM Btu	(6,900)	(0.073)
Process water	1,880,400 M gal	0.04/M gal[b]	75,200	0.798
Electricity	35,630,000 kwh	0.006/kwh[b]	213,800	2.270
Maintenance				
Labor and material, .06 x			874,100	9.279
Analyses			73,000	0.775
Subtotal conversion costs			2,053,800	21.803
Subtotal direct costs			2,166,200	22.995
Indirect Costs				
Depreciation at 10% of fixed investment			1,456,800	15.466
Local taxes and insurance at 2% of fixed investment			291,400	3.093
Overhead				
Plant, 20% of conversion costs			410,800	4.361
Administrative, research, and service, 7% of conversion costs			143,800	1.527
Subtotal indirect costs			2,302,800	24.447
Total annual manufacturing costs for H_2SO_4			4,469,000	47.442

[a] Basis:

Fuel oil burned, 5,033,600 BBL/yr—9,000 Btu/kwh.

Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.

Stack gas reheat to 175°F.

Midwest plant location—1972 costs.

Capital investment, $14,568,000; working capital, $372,700.

[b] Cost of utility supplied from power plant at full value.

Table A-70. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(500-mw existing oil-fired power unit, 2.5% S in fuel; 60,200 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	592 tons	102.40/ton	60,600	1.006
Coke	416 tons	23.50/ton	9,800	.163
Catalyst	981 liters	1.51/liter	1,500	.025
Subtotal raw material			71,900	1.194
Conversion costs				
Operating labor and supervision	32,520 man-hr	6.00/man-hr	195,100	3.241
Utilities				
Fuel oil	5,256,000 gal	0.09/gal	473,000	7.857
Heat credit	11,070 MM Btu	-0.40/MM Btu	(4,400)	(.073)
Process water	1,268,800 M gal	0.05/M gal[b]	63,400	1.053
Electricity	30,450,000 kwh	0.006/kwh[b]	182,700	3.035
Maintenance				
Labor and material, .06 x 13,920,000			835,200	13.874
Analyses			68,000	1.130
Subtotal conversion costs			1,813,000	30.117
Subtotal direct costs			1,884,900	31.311
Indirect Costs				
Depreciation at 10% of fixed investment			1,392,000	23.123
Local taxes and insurance at 2% of fixed investment			278,400	4.624
Overhead				
Plant, 20% of conversion costs			362,600	6.023
Administrative, research, and service, 7% of conversion costs			126,900	2.108
Subtotal indirect costs			2,159,900	35.878
Total annual manufacturing costs for H_2SO_4			4,044,800	67.189

[a] Basis:
Fuel oil burned, 5,145,400 BBL/yr–9,200 Btu/kwh.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Stack gas reheat to 175°F.
Midwest plant location–1972 costs.
Capital investment, $13,920,000; working capital, $323,800.

[b] Cost of utility supplied from power plant at full value.

Table A-71. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme A—Magnesia Slurry Scrubbing-Regeneration

(1000-mw new oil-fired power unit, 2.5% S in fuel; 113,900 tons/yr 100% H_2SO_4)

Direct Costs	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Delivered raw material				
Magnesium oxide (98%)	1,108 tons	102.40/ton	113,500	.997
Coke	787 tons	23.50/ton	18,500	.162
Catalyst	1,856 liters	1.51/liter	2,800	.025
Subtotal raw material			134,800	1.184
Conversion costs				
Operating labor and supervision	39,200 man-hr	6.00/man-hr	235,200	2.065
Utilities				
Fuel oil	9,940,000 gal	0.09/gal	894,600	7.854
Heat credit	20,940 MM Btu	-0.40/MM Btu	(8,400)	(.074)
Process water	2,399,600 M gal	0.04/M gal[b]	96,000	.843
Electricity	57,640,000 kwh	0.005/kwh[b]	288,200	2.530
Maintenance				
Labor and material, .05 x 18,888,000			944,400	8.292
Analyses			121,000	1.062
Subtotal conversion costs			2,571,000	22.572
Subtotal direct costs			2,705,800	23.756
Indirect Costs				
Depreciation at 10% of fixed investment			1,888,800	16.583
Local taxes and insurance at 2% of fixed investment			377,800	3.317
Overhead				
Plant, 20% of conversion costs			514,200	4.515
Administrative, research, and service, 7% of conversion costs			180,000	1.580
Subtotal indirect costs			2,960,800	25.995
Total annual manufacturing costs for H_2SO_4			5,666,600	49.751

[a] Basis:

Fuel oil burned, 9,731,500 BBL/yr–8,700 Btu/kwh.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Stack gas reheat to 175°F.
Midwest plant location–1972 costs.
Capital investment, $18,888,000; working capital, $465,500.

[b] Cost of utility supplied from power plant at full value.

Table A-72. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme B—MgO-MnO$_2$ Slurry Scrubbing-Regeneration

(200-mw new coal-fired power unit, 3.5% S in fuel; 45,200 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Lime	54.8 tons	16.00/ton	900	.020
Magnesium oxide (98%)	448 tons	102.40/ton	45,900	1.015
Manganese dioxide	301 tons	90.00/ton	27,100	.600
Catalyst	736 liters	1.51/liter	1,100	.024
Subtotal raw material			75,000	1.659
Conversion costs				
Operating labor and supervision	30,440 man-hr	6.00/man-hr	182,600	4.040
Utilities				
Fuel oil	2,374,000 gal	0.09/gal	213,700	4.728
Steam	180,000 M lb	0.60/M lb[b]	108,000	2.389
Heat credit	40,100 MM Btu	-0.40/MM Btu	(16,000)	(.354)
Process water	903,000 M gal	0.05/M gal[b]	45,200	1.000
Electricity	24,070,000 kwh	0.007/kwh[b]	168,500	3.728
Maintenance				
Labor and material, .07 x 11,990,000			839,300	18.569
Analyses			45,000	.995
Subtotal conversion costs			1,586,300	35.095
Subtotal direct costs			1,661,300	36.754
Indirect Costs				
Depreciation at 10% of fixed investment			1,199,000	26.527
Local taxes and insurance at 2% of fixed investment			239,800	5.305
Overhead				
Plant, 20% of conversion costs			317,300	7.020
Administrative, research, and service, 7% of conversion costs			111,000	2.456
Subtotal indirect costs			1,867,100	41.308
Total annual manufacturing costs for H_2SO_4			3,528,400	78.062

[a] Basis:

Coal burned, 536,700 tons/yr–9,200 Btu/kwh.

Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.

Stack gas reheat to 175° F.

Midwest plant location–1972 costs.

Capital investment, $11,990,000; working capital, $285,600

[b] Cost of utility supplied from power plant at full value.

Table A-73. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme B—MgO-MnO_2 Slurry Scrubbing-Regeneration

(500-mw new coal-fired power unit, 3.5% S in fuel; 110,400 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Lime	134.1 tons	16.00/ton	2,100	.019
Magnesium oxide (98%)	1,086 tons	102.40/ton	111,200	1.007
Manganese dioxide	724 tons	90.00/ton	65,200	.591
Catalyst	1,798 liters	1.51/liter	2,700	.024
Subtotal raw material			181,200	1.641
Conversion costs				
Operating labor and supervision	39,200 man-hr	6.00/man-hr	235,200	2.130
Utilities				
Fuel oil	5,806,000 gal	0.09/gal	522,500	4.733
Steam	440,000 M lb	0.55/M lb[b]	242,000	2.192
Heat credit	98,000 MM Btu	-0.40/MM Btu	(39,200)	(.355)
Process water	2,207,000 M gal	0.03/M gal[b]	66,200	.600
Electricity	58,870,000 kwh	0.006/kwh[b]	353,200	3.199
Maintenance				
Labor and material, .06 × 22,237,000			1,334,200	12.085
Analyses			85,000	.770
Subtotal conversion costs			2,799,100	25.354
Subtotal direct costs			2,980,300	26.995
Indirect Costs				
Depreciation at 10% of fixed investment			2,223,700	20.142
Local taxes and insurance at 2% of fixed investment			444,700	4.028
Overhead				
Plant, 20% of conversion costs			559,800	5.071
Administrative, research, and service, 7% of conversion costs			195,900	1.775
Subtotal indirect costs			3,424,100	31.016
Total annual manufacturing costs for H_2SO_4			6,404,400	58.011

[a] Basis:
Coal burned, 1,312,500 tons/yr–9,000 Btu/kwh.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Stack gas reheat to 175° F.
Midwest plant location–1972 costs.
Capital investment, $22,237,000; working capital, $513,400.

[b] Cost of utility supplied from power plant at full value.

Table A-74. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme B—MgO-MnO$_2$ Slurry Scrubbing-Regeneration

(1000-mw new coal-fired power unit, 3.5% S in fuel; 213,500 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Lime	259.2 tons	16.00/ton	4,100	.019
Magnesium oxide (98%)	2,078 tons	102.40/ton	212,800	.997
Manganese dioxide	1,385 tons	90.00/ton	124,700	.584
Catalyst	3,477 liters	1.51/liter	5,300	.025
Subtotal raw material			346,900	1.625
Conversion costs				
Operating labor and supervision	47,960 man-hr	6.00/man-hr	287,800	1.348
Utilities				
Fuel oil	11,225,000 gal	0.09/gal	1,010,300	4.732
Steam	850,000 M lb	0.50/M lb[b]	425,000	1.991
Heat credit	189,500 MM Btu	-0.40/MM Btu	(75,800)	(.355)
Process water	4,266,000 M gal	0.02/M gal[b]	85,300	.399
Electricity	113,810,000 kwh	0.005/kwh[b]	569,100	2.665
Maintenance				
Labor and material, .05 x 33,838,000			1,691,900	7.925
Analyses			140,000	.656
Subtotal conversion costs			4,133,600	19.361
Subtotal direct costs			4,480,500	20.986
Indirect Costs				
Depreciation at 10% of fixed investment			3,383,800	15.849
Local taxes and insurance at 2% of fixed investment			676,800	3.170
Overhead				
Plant, 20% of conversion costs			826,700	3.872
Administrative, research, and service, 7% of conversion costs			289,400	1.356
Subtotal indirect costs			5,176,700	24.247
Total annual manufacturing costs for H_2SO_4			9,657,200	45.233

[a] Basis:

Coal burned, 2,537,500 tons/yr–8,700 Btu/kwh.

Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.

Stack gas reheat to 175° F.

Midwest plant location–1972 costs.

Capital investment, $33,838,000; working capital, $773,400.

[b] Cost of utility supplied from power plant at full value.

Table A-75. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme B—MgO-MnO$_2$ Slurry Scrubbing-Regeneration

(200-mw new oil-fired power unit, 2.5% S in fuel; 24,100 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	239 tons	102.40/ton	24,500	1.017
Manganese dioxide	159 tons	90.00/ton	14,300	.593
Catalyst	393 liters	1.51/liter	600	.025
Subtotal raw material			39,400	1.635
Conversion costs				
Operating labor and supervision	28,360 man-hr	6.00/man-hr	170,200	7.062
Utilities				
Fuel oil	1,821,000 gal	0.09/gal	163,900	6.801
Heat credit	21,400 MM Btu	-0.40/MM Btu	(8,600)	(.357)
Process water	498,000 M gal	0.07/M gal[b]	34,900	1.448
Electricity	9,320,000 kwh	0.007/kwh[b]	65,200	2.705
Maintenance				
Labor and material, .07 × 6,806,000			476,400	19.768
Analyses			30,000	1.245
Subtotal conversion costs			932,000	38.672
Subtotal direct costs			971,400	40.307
Indirect Costs				
Depreciation at 10% of fixed investment			680,600	28.241
Local taxes and insurance at 2% of fixed investment			136,100	5.647
Overhead				
Plant, 20% of conversion costs			186,400	7.734
Administrative, research, and service, 7% of conversion costs			65,200	2.706
Subtotal indirect costs			1,068,300	44.328
Total annual manufacturing costs for H_2SO_4			2,039,700	84.635

[a] Basis:
Fuel oil burned, 2,058,200 BBL/yr–9,200 Btu/kwh.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Stack gas reheat to 175° F.
Midwest plant location–1972 costs.
Capital investment, $6,806,000; working capital, $169,000.

[b] Cost of utility supplied from power plant at full value.

Table A-76. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a] Scheme B—MgO-MnO$_2$ Slurry Scrubbing-Regeneration

(500-mw new oil-fired power unit, 2.5% S in fuel; 58,900 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	579 tons	102.40/ton	59,300	1.007
Manganese dioxide	386 tons	90.00/ton	34,700	.589
Catalyst	959 liters	1.51/liter	1,400	.024
Subtotal raw material			95,400	1.620
Conversion costs				
Operating labor and supervision	32,520 man-hr	6.00/man-hr	195,100	3.312
Utilities				
Fuel oil	4,454,000 gal	0.09/gal	400,900	6.807
Heat credit	52,300 MM Btu	-0.40/MM Btu	(20,900)	(.355)
Process water	1,217,000 M gal	0.05/M gal[b]	60,900	1.034
Electricity	22,780,000 kwh	0.006/kwh[b]	136,700	2.321
Maintenance				
Labor and material, .06 x 12,561,000			753,700	12.796
Analyses			66,000	1.120
Subtotal conversion costs			1,592,400	27.035
Subtotal direct costs			1,687,800	28.655
Indirect Costs				
Depreciation at 10% of fixed investment			1,256,100	21.326
Local taxes and insurance at 2% of fixed investment			251,200	4.265
Overhead				
Plant, 20% of conversion costs			318,500	5.407
Administrative, research, and service, 7% of conversion costs			111,500	1.894
Subtotal indirect costs			1,937,300	32.892
Total annual manufacturing costs for H_2SO_4			3,625,100	61.547

[a] Basis:
Fuel oil burned, 5,033,600 BBL/yr–9,000 Btu/kwh.
Power unit on-stream time, 7 000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Stack gas reheat to 175° F.
Midwest plant location–1972 costs.
Capital investment, $12,561,000; working capital, $294,800.

[b] Cost of utility supplied from power plant at full value.

Table A-77. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]
Scheme B—MgO-MnO$_2$ Slurry Scrubbing-Regeneration

(1000-mw new oil-fired power unit, 2.5% S in fuel; 113,900 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	1,108 tons	102.40/ton	113,500	.996
Manganese dioxide	739 tons	90.00/ton	66,500	.584
Catalyst	1,855 liters	1.51/liter	2,800	.025
Subtotal raw material			182,800	1.605
Conversion costs				
Operating labor and supervision	39,200 man-hr	6.00/man-hr	235,200	2.065
Utilities				
Fuel oil	8,611,000 gal	0.09/gal	775,000	6.805
Heat credit	101,000 MM Btu	-0.40/MM-Btu	(40,400)	(.355)
Process water	2,352,000 M gal	0.04/M gal[b]	94,100	.826
Electricity	44,050,000 kwh	0.005/kwh[b]	220,300	1.934
Maintenance				
Labor and material, .05 x 19,126,000			956,300	8.396
Analyses			121,000	1.062
Subtotal conversion costs			2,361,500	20.733
Subtotal direct costs			2,544,300	22.338
Indirect Costs				
Depreciation at 10% of fixed investment			1,912,600	16.792
Local taxes and insurance at 2% of fixed investment			382,500	3.358
Overhead				
Plant, 20% of conversion costs			472,300	4.147
Administrative, research, and service, 7% of conversion costs			165,300	1.451
Subtotal indirect costs			2,932,700	25.748
Total annual manufacturing costs for H_2SO_4			5,477,000	48.086

[a] Basis:
Fuel oil burned, 9,731,500 BBL/yr–8,700 Btu/kwh.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Stack gas reheat to 175° F.
Midwest plant location–1972 costs.
Capital investment, $19,126,000; working capital, $445,700.

[b] Cost of utility supplied from power plant at full value.

Table A-78. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme C—Magnesia Clear Liquor Scrubbing-Regeneration

(200-mw new coal-fired power unit, 3.5% S in fuel; 38,700 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	373 tons	102.40/ton	38,200	.987
Coke	130 tons	23.50/ton	3,100	.080
Catalyst	630 liters	1.51/liter	1,000	.026
Subtotal raw material			42,300	1.093
Conversion costs				
Operating labor and supervision	30,440 man-hr	6.00/man-hr	182,600	4.718
Utilities				
Fuel oil	1,836,000 gal	0.09/gal	165,200	4.269
Steam	247,000 M lb	0.60/M lb[b]	148,200	3.829
Heat credit	40,400 MM Btu	-0.40/MM Btu	(16,200)	(.419)
Process water	837,300 M gal	0.05/M gal[b]	41,900	1.083
Electricity	24,583,000 kwh	0.007/kwh[b]	172,100	4.447
Maintenance				
Labor and material, .07 x 9,923,000			694,600	17.948
Analyses			38,000	.982
Subtotal conversion costs			1,426,400	36.858
Subtotal direct costs			1,468,700	37.951
Indirect Costs				
Depreciation at 10% of fixed investment			992,300	25.641
Local taxes and insurance at 2% of fixed investment			198,500	5.129
Overhead				
Plant, 20% of conversion costs			285,300	7.372
Administrative, research, and service, 7% of conversion costs			99,800	2.579
Subtotal indirect costs			1,575,900	10.721
Total annual manufacturing costs for H_2SO_4			3,044,600	78.672

[a] Basis:
Coal burned, 536,700 tons/yr–9,200 Btu/kwh.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Stack gas reheat to 175°F.
Midwest plant location–1972 costs.
Capital investment, $9,923,000; working capital, $252,000.

[b] Cost of utility supplied from power plant at full value.

Table A-79. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a] Scheme C—Magnesia Clear Liquor Scrubbing-Regeneration

(500-mw new coal-fired power unit, 3.5% S in fuel; 94,700 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	911 tons	102.40/ton	93,300	.986
Coke	319 tons	23.50/ton	7,500	.079
Catalyst	1,542 liters	1.51/liter	2,300	.024
Subtotal raw material			103,100	1.089
Conversion costs				
Operating labor and supervision	39,200 man-hr	6.00/man-hr	235,200	2.484
Utilities				
Fuel oil	4,490,000 gal	0.09/gal	404,100	4.267
Steam	604,000 M lb	0.55/M lb[b]	332,200	3.508
Heat credit	98,700 MM Btu	-0.40/MM Btu	(39,500)	(.417)
Process water	2,048,800 M gal	0.03/M gal[b]	61,500	.649
Electricity	60,119,000 kwh	0.006/kwh[b]	360,700	3.809
Maintenance				
Labor and material, .06 x 18,111,000			1,086,700	11.475
Analyses			73,000	.771
Subtotal conversion costs			2,513,900	26.546
Subtotal direct costs			2,617,000	27.635
Indirect Costs				
Depreciation at 10% of fixed investment			1,811,100	19.125
Local taxes and insurance at 2% of fixed investment			362,200	3.825
Overhead				
Plant, 20% of conversion costs			502,800	5.309
Administrative, research, and service, 7% of conversion costs			176,000	1.858
Subtotal indirect costs			2,852,100	30.117
Total annual manufacturing costs for H_2SO_4			5,469,100	57.752

[a] Basis:
Coal burned, 1,312,500 tons/yr–9,000 Btu/kwh.
Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.
Stack gas reheat to 175° F.
Midwest plant location–1972 costs.
Capital investment, $18,111,000; working capital, $449,600.

[b] Cost of utility supplied from power plant at full value.

Table A-80. Nonregulated Company Economics—Total Venture Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]

Scheme C—Magnesia Clear Liquor Scrubbing-Regeneration

(1000-mw new coal-fired power unit, 3.5% S in fuel; 183,000 tons/yr 100% H_2SO_4)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium oxide (98%)	1,761 tons	102.40/ton	180,300	.985
Coke	617 tons	23.50/ton	14,500	.079
Catalyst	2,980 liters	1.51/liter	4,500	.025
Subtotal raw material			199,300	1.089
Conversion costs				
Operating labor and supervision	47,960 man-hr	6.00/man-hr	287,800	1.573
Utilities				
Fuel oil	8,681,000 gal	0.09/gal	781,300	4.269
Steam	1,168,000 M lb	0.50/M lb[b]	584,000	3.191
Heat credit	190,800 MM Btu	-0.40/MM Btu	(76,300)	(.417)
Process water	3,961,500 M gal	0.02/M gal[b]	79,200	.433
Electricity	116,228,000 kwh	0.005/kwh[b]	581,100	3.175
Maintenance				
Labor and material, .05 x 27,540,000			1,377,000	7.525
Analyses			119,000	.650
Subtotal conversion costs			3,733,100	20.399
Subtotal direct costs			3,932,400	21.488
Indirect Costs				
Depreciation at 10% of fixed investment			2,754,000	15.049
Local taxes and insurance at 2% of fixed investment			550,800	3.010
Overhead				
Plant, 20% of conversion costs			746,600	4.080
Administrative, research, and service, 7% of conversion costs			261,300	1.428
Subtotal indirect costs			4,312,700	23.567
Total annual manufacturing costs for H_2SO_4			8,245,100	45.055

[a] Basis:

Coal burned, 2,537,500 tons/yr–8,700 Btu/kwh.

Power unit on-stream time, 7,000 hr/yr; acid plant on-stream time, 7,000 hr/yr.

Stack gas reheat to 175°F.

Midwest plant location–1972 costs.

Capital investment, $27,540,000; working capital, $676,500.

[b] Cost of utility supplied from power plant at full value.

Table A-81. Cooperative Economics—Joint Power-Chemical Company Venture
Regulated Power Company Portion
Annual Manufacturing Costs for Mangesium Sulfite from Scrubbed Power Plant Stack Gas[a]
Scheme D—Magnesia Slurry Scrubbing-Drying System

(200-mw new coal-fired power unit, 3.5% S in fuel; 56,250 tons/yr $MgSO_3$)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of $MgSO_3$, $
Direct Costs				
Delivered raw material				
Lime	54.8 tons	16.00/ton	900	0.016
Make-up magnesium oxide (98%)	623 tons	102.40/ton	63,800	1.135
Shipping cost for recycle MgO[c]	23,600 tons	2.40/ton	56,600	1.006
Subtotal raw material			121,300	2.157
Conversion costs				
Operating labor and supervision	21,680 man-hr	6.00/man-hr	130,100	2.313
Utilities				
Fuel oil	1,014,000 gal	0.09/gal	91,300	1.623
Steam	80,000 M lb	0.60/M lb[b]	48,000	0.853
Process water	85,000 M gal	0.05/M gal	4,300	0.076
Electricity	22,523,000 kwh	0.007/kwh[b]	158,000	2.809
Maintenance				
Labor and material, .07 x 7,671,000			537,000	9.547
Analyses			27,000	0.480
Subtotal conversion costs			995,700	17.701
Subtotal direct costs			1,117,000	19.858
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			1,143,000	20.320
Overhead				
Plant, 20% of conversion costs			199,100	3.540
Administrative, research, and service			39,800	0.708
Subtotal indirect costs			1,381,900	24.568

	Cost/ton of coal burned, $	Total annual cost, $	Cost/ton of $MgSO_3$, $
Total annual manufacturing costs for $MgSO_3$	4.656	2,498,900	44.426

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 536,700 tons/yr—9,200 Btu/kwh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location—1972 costs.
Capital investment, $7,671,000; working capital, $189,600.

[b] Cost of utility supplied from power plant at full value.

[c] Average shipping distance between power plant and regeneration plant—25 miles, truck shipping assumed.

Table A-82. Cooperative Economics—Joint Power-Chemical Company Venture
Nonregulated Chemical Company Portion
Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]
Scheme D—Magnesia Regeneration-Acid Manufacture

(Equivalent to 200-mw new coal-fired power unit, 3.5% S in fuel; 45,200 tons/yr 100% H_2SO_4)
Magnesium sulfite source—one 200-mw unit

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium sulfite	56,250 tons	44.43/ton	2,498,900	55.285
Shipping cost for magnesium sulfite[c]	56,250 tons	2.40/ton	135,000	2.987
Coke	312 tons	23.50/ton	7,300	0.162
Catalyst	736 liters	1.51/liter	1,100	0.024
Subtotal raw material			2,642,300	58.458
Conversion costs				
Operating labor and supervision	21,680 man-hr	6.00/man-hr	130,100	2.877
Utilities				
Fuel oil	1,141,000 gal	0.09/gal	102,700	2.272
Heat credit	4,352 MM Btu	-0.40/MM Btu	(1,700)	(0.038)
Process water	820,000 M gal	0.05/M gal[b]	41,000	0.907
Electricity	5,033,600 kwh	0.006/kwh[b]	30,200	0.668
Maintenance				
Labor and material, .07 x 5,017,000			351,200	7.770
Analyses			18,000	0.398
Subtotal conversion costs			671,500	14.854
Subtotal direct costs			3,313,800	73.312
Indirect Costs				
Depreciation at 10% of fixed investment			501,700	11.100
Local taxes and insurance at 2% of fixed investment			100,300	2.220
Overhead				
Plant, 20% of conversion costs			134,300	2.971
Administrative, research, and service			99,400	2.200
Subtotal indirect costs			835,700	18.491
Total annual manufacturing costs for H_2SO_4			4,149,500	91.303

[a] Basis:
Midwest plant location—1972 costs.
Acid plant on-stream time, 8,000 hr/yr.
Acid stack gas reheat to 175° F.
Capital investment, $5,017,000; working capital, $629,200.

[b] Cost of utility supplied at full value.

[c] Average shipping distance between Power Plant and Regeneration-Acid Plant—25 miles, truck shipping assumed.

Table A-83. Cooperative Economics—Joint Power-Chemical Company Venture
Nonregulated Chemical Company Portion
Annual Manufacturing Costs for 98% H_2SO_4
from Scrubbed Power Plant Stack Gas[a]
Scheme D—Magnesia Regeneration-Acid Manufacture

(Equivalent to 1000-mw new coal-fired power unit, 3.5% S in fuel; 226,000 tons/yr 100% H_2SO_4)
Magnesium sulfite source—five 200-mw units

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium sulfite	281,250 tons	44.43/ton	12,494,500	55.285
Shipping cost for magnesium sulfite[c]	281,250 tons	2.40/ton	675,000	2.987
Coke	1,560 tons	23.50/ton	36,700	0.162
Catalyst	3,680 liters	1.51/liter	5,600	0.024
Subtotal raw material			13,211,800	58.458
Conversion costs				
Operating labor and supervision	30,440 man-hr	6.00/man-hr	182,600	0.808
Utilities				
Fuel oil	5,705,000 gal	0.09/gal	513,500	2.272
Heat credit	21,760 MM Btu	-0.40/MM Btu	(8,700)	(0.039)
Process water	4,100,000 M gal	0.02/M gal[b]	82,000	0.363
Electricity	25,168,000 kwh	0.006/kwh[b]	151,000	0.668
Maintenance				
Labor and material, .04 x 12,354,000			494,200	2.187
Analyses			58,000	0.257
Subtotal conversion costs			1,472,600	6.516
Subtotal direct costs			14,684,400	64.974
Indirect Costs				
Depreciation at 10% of fixed investment			1,235,400	5.466
Local taxes and insurance at 2% of fixed investment			247,100	1.093
Overhead				
Plant, 20% of conversion costs			294,500	1.303
Administrative, research, and service			440,600	1.949
Subtotal indirect costs			2,217,600	9.811
Total annual manufacturing costs for H_2SO_4			16,902,000	74.785

[a] Basis:
Midwest plant location—1972 costs.
Acid plant on-stream time, 8,000 hr/yr.
Acid stack gas reheat to 175° F.
Capital investment, $12,354,000; working capital, $2,834,000.

[b] Cost of utility supplied at full value.

[c] Average shipping distance between Power Plant and Regeneration-Acid Plant—25 miles, truck shipping assumed.

Table A-84. Cooperative Economics—Joint Power-Chemical Company Venture
Nonregulated Chemical Company Portion
Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]
Scheme D—Magnesia Regeneration-Acid Manufacture

(Equivalent to 1000-mw new coal-fired power unit, 3.5% S in fuel, 452,000 tons/yr 100% H_2SO_4)
Magnesium sulfite source—ten 200-mw units

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium sulfite	562,500 tons	44.43/ton	24,989,000	55.285
Shipping cost for magnesium sulfite[c]	562,500 tons	2.40/ton	1,350,000	2.987
Coke	3,120 tons	23.50/ton	73,300	0.162
Catalyst	7,360 liters	1.51/liter	11,100	0.024
Subtotal raw material			26,423,400	58.458
Conversion costs				
Operating labor and supervision	37,120 man-hr	6.00/man-hr	222,700	0.493
Utilities				
Fuel oil	11,410,000 gal	0.09/gal	1,026,900	2.272
Heat credit	43,520 MM Btu	-0.40/MM Btu	(17,400)	(0.039)
Process water	8,200,000 M gal	0.02/M gal[b]	164,000	0.363
Electricity	50,336,000 kwh	0.006/kwh[b]	302,000	0.668
Maintenance				
Labor and material, .04 x 19,534,000			781,400	1.729
Analyses			79,000	0.175
Subtotal conversion costs			2,558,600	5.661
Subtotal direct costs			28,982,000	64.119
Indirect Costs				
Depreciation at 10% of fixed investment			1,953,400	4.322
Local taxes and insurance at 2% of fixed investment			390,700	0.864
Overhead				
Plant, 20% of conversion costs			511,700	1.132
Administrative, research, and service			869,500	1.924
Subtotal indirect costs			3,725,300	8.242
Total annual manufacturing costs for H_2SO_4			32,707,300	72.361

[a] Basis:
Midwest plant location—1972 costs.
Acid plant on-stream time, 8,000 hr/yr.
Acid stack gas reheat to 175° F.
Capital investment, $19,534,000; working capital, $5,604,000.

[b] Cost of utility supplied at full value.

[c] Average shipping distance between Power Plant and Regeneration-Acid Plant—25 miles, truck shipping assumed.

Table A-85. Cooperative Economics—Joint Power-Chemical Company Venture
Nonregulated Chemical Company Portion
Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]
Scheme D—Magnesia Regeneration-Acid Manufacture

(Equivalent to 3000-mw new coal-fired power unit, 3.5% S in fuel; 678,000 tons/yr 100% H_2SO_4)
Magnesium sulfite source—fifteen 200-mw units

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium sulfite	843,750 tons	44.43/ton	37,483,500	55.285
Shipping cost for magnesium sulfite[c]	843,750 tons	2.40/ton	2,025,000	2.987
Coke	4,680 tons	23.50/ton	110,000	0.162
Catalyst	11,040 liters	1.51/liter	16,700	0.024
Subtotal raw material			39,635,200	58.458
Conversion costs				
Operating labor and supervision	39,200 man-hr	6.00/man-hr	235,200	0.347
Utilities				
Fuel oil	17,115,000 gal	0.09/gal	1,540,400	2.273
Heat credit	65,280 MM Btu	-0.40/MM Btu	(26,100)	(0.039)
Process water	12,300,000 M gal	0.02/M gal[b]	246,000	0.363
Electricity	75,504,000 kwh	0.006/kwh[b]	453,000	0.668
Maintenance				
Labor and material, .04 x 26,096,000			1,043,800	1.540
Analyses			105,000	0.155
Subtotal conversion costs			3,597,300	5.307
Subtotal direct costs			43,232,500	63.765
Indirect Costs				
Depreciation at 10% of fixed investment			2,609,600	3.849
Local taxes and insurance at 2% of fixed investment			521,900	0.770
Overhead				
Plant, 20% of conversion costs			719,500	1.061
Administrative, research, and service			1,297,100	1.913
Subtotal indirect costs			5,148,100	7.593
Total annual manufacturing costs for H_2SO_4			48,380,600	71.358

[a] Basis:
Midwest plant location—1972 costs.
Acid plant on-stream time, 8,000 hr/yr.
Acid stack gas reheat to 175° F.
Capital investment, $26,096,000; working capital, $8,366,200

[b] Cost of utility supplied at full value.

[c] Average shipping distance between Power Plant and Regeneration-Acid Plant—25 miles, truck shipping assumed.

Table A-86. Cooperative Economics—Joint Power-Chemical Company Venture
Regulated Power Company Portion
Average Annual Manufacturing Costs for Magnesium Sulfite from Scrubbed Power Plant Stack Gas[a]
Scheme D—Magnesia Slurry Scrubbing-Drying System

(500-mw new coal-fired power unit, 3.5% S in fuel; 133,580 tons/yr 100% $MgSO_3$)

	Annual quantity	Unit cost, \$	Total annual cost, \$	Cost/ton of $MgSO_3$, \$
Direct Costs				
Delivered raw material				
Lime	134.1 tons	16.00/ton	2,100	0.016
Make-up magnesium oxide (98%)	1,480 tons	102.40/ton	151,600	1.135
Shipping cost for recycle MgO[c]	56,000 tons	2.40/ton	134,400	1.006
Subtotal raw material			288,100	2.157
Conversion costs				
Operating labor and supervision	21,680 man-hr	6.00/man-hr	130,000	0.973
Utilities				
Fuel oil	2,480,000 gal	0.09/gal	223,200	1.671
Steam	195,000 M lb	0.55/M lb[b]	107,300	0.803
Process water	208,000 M gal	0.03/M gal[b]	6,200	0.046
Electricity	55,082,000 kwh	0.006/kwh[b]	330,500	2.474
Maintenance				
Labor and material, .06 x 14,844,000			890,600	6.667
Analyses			57,000	0.427
Subtotal conversion costs			1,744,800	13.061
Subtotal direct costs			2,032,900	15.218
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			2,211,800	16.558
Overhead				
Plant, 20% of conversion costs			349,000	2.613
Administrative, research, and service			71,600	.536
Subtotal indirect costs			2,632,400	19.707

	Cost/ton of coal burned, \$	Total annual cost, \$	Cost/ton of $MgSO_3$, \$
Total annual manufacturing costs for $MgSO_3$	3.555	4,665,300	34.925

[a] Basis:

Remaining life of power plant, 30 yr.
Coal burned, 1,312,500 tons/yr–9,000 Btu/kwh.
Stack gas reheat to 175° F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location–1972 costs.
Capital investment, \$14,844,000; working capital, \$334,200.

[b] Cost of utility supplied from power plant at full value.

[c] Average shipping distance between power plant and regeneration plant–25 miles, truck shipping assumed.

Table A-87. Cooperative Economics—Joint Power-Chemical Company Venture
Nonregulated Chemical Company Portion
Annual Manufacturing Costs for 98% H_2SO_4
from Scrubbed Power Plant Stack Gas[a]
Scheme D—Magnesia Regeneration-Acid Manufacture

(Equivalent to 500-mw new coal-fired power unit, 3.5% S in fuel: 110,400 tons/yr 100% H_2SO_4)

Magnesium sulfite source—one 500-mw unit

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium sulfite	133,580 tons	34.93/ton	4,665,300	42.258
Shipping cost for magnesium sulfite[c]	133,580 tons	2.40/ton	320,600	2.904
Coke	740 tons	23.50/ton	17,400	0.158
Catalyst	1,800 liters	1.51/liter	2,700	0.024
Subtotal raw material			5,006,000	45.344
Conversion costs				
Operating labor and supervision	28,360 man-hr	6.00/man-hr	170,200	1.542
Utilities				
Fuel oil	2,790,000 gal	0.09/gal	251,100	2.275
Heat credit	10,884 MM Btu	-0.40/MM Btu	(4,400)	(0.040)
Process water	2,000,702 M gal	0.03/M gal[b]	60,000	0.543
Electricity	12,584,000 kwh	0.006/kwh[b]	75,500	0.684
Maintenance				
Labor and material, .06 x 8,294,000			497,600	4.507
Analyses			38,000	0.344
Subtotal conversion costs			1,088,000	9.855
Subtotal direct costs			6,094,000	55.199
Indirect Costs				
Depreciation at 10% of fixed investment			829,400	7.513
Local taxes and insurance at 2% of fixed investment			165,900	1.503
Overhead				
Plant, 20% of conversion costs			217,600	1.917
Administrative, research, and service			196,500	1.780
Subtotal indirect costs			1,409,400	12.767
Total annual manufacturing costs for H_2SO_4			7,503,400	67.966

[a] Basis:
Midwest plant location–1972 costs.
Acid plant on-stream time, 8,000 hr/yr.
Acid stack gas reheat to 175°F.
Capital investment, $8,294,000; working capital, $1,143,000.

[b] Cost of utility supplied at full value.

[c] Average shipping distance between Power Plant and Regeneration-Acid Plant–25 miles, truck shipping assumed.

Table A-88. Cooperative Economics—Joint Power-Chemical Company Venture
Nonregulated Chemical Company Portion
Annual Manufacturing Costs for 98% H_2SO_4
from Scrubbed Power Plant Stack Gas[a]
Scheme D—Magnesia Regeneration-Acid Manufacture

(Equivalent to 1000-mw new coal-fired power unit, 3.5% S in fuel; 220,800 tons/yr 100% H_2SO_4)
Magnesium sulfite source—two 500-mw units

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium sulfite	267,160 tons	34.93/ton	9,330,600	42.258
Shipping cost for magnesium sulfite[c]	267,160 tons	2.40/ton	641,200	2.904
Coke	1,480 tons	23.50/ton	34,800	.158
Catalyst	3,600 liters	1.51/liter	5,400	.024
Subtotal raw material			10,012,000	45.344
Conversion costs				
Operating labor and supervision	30,440 man-hr	6.00/man-hr	182,600	.827
Utilities				
Fuel oil	5,770,792 gal	0.09/gal	519,400	2.352
Heat credit	22,504 MM Btu	-0.40/MM Btu	(9,000)	(0.40)
Process water	4,138,220 M gal	0.02/M gal[b]	82,800	.375
Electricity	26,028,545 kwh	0.006/kwh[b]	156,200	.707
Maintenance				
Labor and material, .04 x 12,354,000			494,200	2.238
Analyses			57,000	.258
Subtotal conversion costs			1,483,200	6.717
Subtotal direct costs			11,495,200	52.061
Indirect Costs				
Depreciation at 10% of fixed investment			1,235,400	5.595
Local taxes and insurance at 2% of fixed investment			247,100	1.119
Overhead				
Plant, 20% of conversion costs			296,600	1.343
Administrative, research, and service			342,800	1.552
Subtotal indirect costs			2,121,700	9.609
Total annual manufacturing costs for H_2SO_4			13,616,900	61.670

[a] Basis:
Midwest plant location—1972 costs.
Acid plant on-stream time, 8,000 hr/yr.
Acid stack gas reheat to 175° F.
Capital investment, $12,354,000; working capital, $2,163,000.

[b] Cost of utility supplied at full value.

[c] Average shipping distance between Power Plant and Regeneration-Acid Plant—25 miles, truck shipping assumed.

Table A-89. Cooperative Economics—Joint Power-Chemical Company Venture
Nonregulated Chemical Company Portion
Annual Manufacturing Costs for 98% H_2SO_4 from Scrubbed Power Plant Stack Gas[a]
Scheme D—Magnesia Regeneration-Acid Manufacture

(Equivalent to 2000-mw new coal-fired power unit, 3.5% S in fuel; 441,600 tons/yr 100% H_2SO_4)
Magnesium sulfite source—four 500-mw units

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium sulfite	534,320 tons	34.93/ton	18,661,200	42.258
Shipping cost for magnesium sulfite[c]	534,320 tons	2.40/ton	1,282,400	2.904
Coke	2,960 tons	23.50/ton	69,600	0.158
Catalyst	7,200 liters	1.51/liter	10,800	0.024
Subtotal raw material			20,024,000	45.344
Conversion costs				
Operating labor and supervision	37,120 man-hr	6.00/man-hr	222,700	0.504
Utilities				
Fuel oil	11,541,584 gal	0.09/gal	1,038,700	2.352
Heat credit	45,008 MM Btu	-0.40/MM Btu	(18,000)	(0.041)
Process water	8,276,440 M gal	0.02/M gal[b]	165,500	0.375
Electricity	52,057,090 kwh	0.006/kwh[b]	312,300	0.707
Maintenance				
Labor and material, .04 x 19,534,000			781,400	1.770
Analyses			77,000	0.174
Subtotal conversion costs			2,579,600	5.841
Subtotal direct costs			22,603,600	51.185
Indirect Costs				
Depreciation at 10% of fixed investment			1,953,400	4.423
Local taxes and insurance at 2% of fixed investment			390,700	0.885
Overhead				
Plant, 20% of conversion costs			515,900	1.168
Administrative, research, and service			658,100	1.491
Subtotal indirect costs			3,518,100	7.967
Total annual manufacturing costs for H_2SO_4			26,121,700	59.152

[a] Basis:
Midwest plant location—1972 costs.
Acid plant on-stream time, 8,000 hr/yr.
Acid stack gas reheat to 175° F.
Capital investment, $19,534,000; working capital, $4,260,000.

[b] Cost of utility supplied at full value.

[c] Average shipping distance between Power Plant and Regeneration-Acid Plant—25 miles, truck shipping assumed.

Table A-90. Cooperative Economics—Joint Power-Chemical Company Venture
Nonregulated Chemical Company Portion
Annual Manufacturing Costs for 98% H_2SO_4
from Scrubbed Power Plant Stack Gas[a]
Scheme D—Magnesia Regeneration-Acid Manufacture

(Equivalent to 3000-mw new coal-fired power unit, 3.5% S in fuel; 662,400 tons/yr 100% H_2SO_4)
Magnesium sulfite source—six 500-mw units

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium sulfite	801,480 tons	34.93/ton	27,991,800	42.258
Shipping cost for magnesium sulfite[c]	801,480 tons	2.40/ton	1,923,600	2.904
Coke	4,440 tons	23.50/ton	104,300	.158
Catalyst	10,800 liters	1.51/liter	16,300	.024
Subtotal raw material			30,036,000	45.344
Conversion costs				
Operating labor and supervision	39,200 man-hr	6.00/man-hr	235,200	0.355
Utilities				
Fuel oil	17,312,376 gal	0.09/gal	1,558,100	2.352
Heat credit	67,512 MM Btu	-0.40/MM Btu	(27,000)	(0.041)
Process water	12,414,660 M gal	0.02/M gal[b]	248,300	0.375
Electricity	78,085,635 kwh	0.006/kwh[b]	468,500	.707
Maintenance				
Labor and material, .03 x 26,096,000			782,900	1.182
Analyses			102,000	0.154
Subtotal conversion costs			3,368,000	5.084
Subtotal direct costs			33,404,000	50.428
Indirect Costs				
Depreciation at 10% of fixed investment			2,609,600	3.940
Local taxes and insurance at 2% of fixed investment			521,900	0.788
Overhead				
Plant, 20% of conversion costs			673,600	1.017
Administrative, research, and service			952,100	1.437
Subtotal indirect costs			4,757,200	7.182
Total annual manufacturing costs for H_2SO_4			38,161,200	57.610

[a] Basis:
Midwest plant location—1972 costs.
Acid plant on-stream time, 8,000 hr/yr.
Acid stack gas reheat to 175°F.
Capital investment, $26,096,000; working capital, $6,304,200.

[b] Cost of utility supplied at full value.

[c] Average shipping distance between Power Plant and Regeneration-Acid Plant—25 miles, truck shipping assumed.

Table A-91. Cooperative Economics—Joint Power-Chemical Company Venture
Regulated Power Company Portion
Annual Manufacturing Costs for Magnesium Sulfite from Scrubbed Power Plant Stack Gas[a]
Scheme D—Magnesia Slurry Scrubbing-Drying System

(1000-mw new coal-fired power unit, 3.5% S in fuel; 258,250 tons/yr $MgSO_3$)

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of $MgSO_3$, $
Direct Costs				
Delivered raw material				
Lime	259.2 tons	16.00/ton	4,100	0.016
Make-up magnesium oxide (98%)	2,861 tons	102.40/ton	293,000	1.134
Shipping cost for recycle MgO[c]	108,265 tons	2.40/ton	259,800	1.006
Subtotal raw material			556,900	2.156
Conversion costs				
Operating labor and supervision	30,440 man-hr	6.00/man-hr	182,600	0.707
Utilities				
Fuel oil	4,795,000 gal	0.09/gal	431,600	1.671
Steam	377,000 M lb	0.50/M lb[b]	188,500	0.730
Process water	402,000 M gal	0.02/M gal[b]	8,000	0.031
Electricity	106,490,000 kwh	0.005/kwh[b]	532,500	2.062
Maintenance				
Labor and material, .06 x 22,673,000			1,360,400	5.268
Analyses			94,000	0.364
Subtotal conversion costs			2,797,600	10.833
Subtotal direct costs			3,354,500	12.989
Indirect Costs				
Average capital charges at 14.9% of initial fixed investment			3,378,300	13.081
Overhead				
Plant, 20% of conversion costs			559,500	2.167
Administrative, research, and service			117,000	.453
Subtotal indirect costs			4,054,800	15.701

	Cost/ton of coal burned, $	Total annual cost, $	Cost/ton of $MgSO_3$, $
Total annual manufacturing costs for $MgSO_3$	2.920	7,409,300	28.690

[a] Basis:
Remaining life of power plant, 30 yr.
Coal burned, 2,537,500 tons/yr–8,700 Btu/kwh.
Stack gas reheat to 175°F.
Power unit on-stream time, 7,000 hr/yr.
Midwest plant location–1972 costs.
Capital investment, $22,673,000; working capital, $568,300.

[b] Cost of utility supplied from power plant at full value.

[c] Average shipping distance between power plant and regeneration plant–25 miles, truck shipping assumed.

Table A-92. Cooperative Economics—Joint Power-Chemical Company Venture
Nonregulated Chemical Company Portion
Annual Manufacturing Costs for 98% H_2SO_4
from Scrubbed Power Plant Stack Gas[a]
Scheme D—Magnesia Regeneration-Acid Manufacture

(Equivalent to 1000-mw new coal-fired power unit, 3.5% S in fuel; 213,500 tons/yr 100% H_2SO_4)

Magnesium sulfite source—one 1000-mw unit

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium sulfite	258,250 tons	28.69/ton	7,409,300	34.704
Shipping cost for magnesium sulfite[c]	258,250 tons	2.40/ton	619,800	2.903
Coke	1,480 tons	23.50/ton	34,800	0.163
Catalyst	3,480 liters	1.51/liter	5,200	0.024
Subtotal raw material			8,069,100	37.794
Conversion costs				
Operating labor and supervision	30,440 man-hr	6.00/man-hr	182,600	0.855
Utilities				
Fuel oil	5,580,000 gal	0.09/gal	502,200	2.352
Heat credit	21,760 MM Btu	-0.40/MM Btu	(8,700)	(0.040)
Process water	4,001,404 M gal	0.02/M gal[b]	80,000	0.375
Electricity	25,168,000 kwh	0.006/kwh[b]	151,000	0.707
Maintenance				
Labor and material, .04 x 12,354,000			494,200	2.315
Analyses			56,000	0.262
Subtotal conversion costs			1,457,300	6.826
Subtotal direct costs			9,526,400	44.620
Indirect Costs				
Depreciation at 10% of fixed investment			1,235,400	5.786
Local taxes and insurance at 2% of fixed investment			247,000	1.157
Overhead				
Plant, 20% of conversion costs			291,500	1.365
Administrative, research, and service			290,900	1.362
Subtotal indirect costs			2,064,800	9.670
Total annual manufacturing costs for H_2SO_4			11,591,200	54.290

[a] Basis:
Midwest plant location–1972 costs.
Acid plant on-stream time, 8,000 hr/yr.
Acid stack gas reheat to 175°F.
Capital investment, $12,354,000; working capital, $1,833,200.

[b] Cost of utility supplied at full value.

[c] Average shipping distance between Power Plant and Regeneration-Acid Plant–25 miles, truck shipping assumed.

Table A-93. Cooperative Economics—Joint Power-Chemical Company Venture
Nonregulated Chemical Company Portion
Annual Manufacturing Costs for 98% H_2SO_4
from Scrubbed Power Plant Stack Gas[a]
Scheme D—Magnesia Regeneration-Acid Manufacture

(Equivalent to 2000-mw new coal-fired power unit, 3.5% S in fuel; 427,000 tons/yr 100% H_2SO_4)
Magnesium sulfite source—two 1000-mw units

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium sulfite	516,500 tons	28.69/ton	14,818,600	34.704
Shipping cost for magnesium sulfite[c]	516,500 tons	2.40/ton	1,239,600	2.903
Coke	2,960 tons	23.50/ton	69,600	0.163
Catalyst	6,960 liters	1.51/liter	10,500	0.025
Subtotal raw material			16,138,300	37.795
Conversion costs				
Operating labor and supervision	37,120 man-hr	6.00/man-hr	222,700	0.521
Utilities				
Fuel oil	11,160,000 gal	0.09/gal	1,004,400	2.352
Heat credit	43,520 MM Btu	-0.40/MM Btu	(17,400)	(0.041)
Process water	8,002,808 M gal	0.02/M gal[b]	160,000	0.375
Electricity	50,336,000 kwh	0.006/kwh[b]	302,000	0.707
Maintenance				
Labor and material, .04 x 19,534,000			781,400	1.830
Analyses			75,000	0.176
Subtotal conversion costs			2,528,100	5.920
Subtotal direct costs			18,666,400	43.715
Indirect Costs				
Depreciation at 10% of fixed investment			1,953,400	4.574
Local taxes and insurance at 2% of fixed investment			390,700	0.915
Overhead				
Plant, 20% of conversion costs			505,600	1.184
Administrative, research, and service			554,800	1.300
Subtotal indirect costs			3,404,500	7.973
Total annual manufacturing costs for H_2SO_4			22,070,900	51.688

[a] Basis:
Midwest plant location—1972 costs.
Acid plant on-stream time, 8,000 hr/yr.
Acid stack gas reheat to 175° F.
Capital investment, $19,534,000; working capital, $3,600,500.

[b] Cost of utility supplied at full value.

[c] Average shipping distance between Power Plant and Regeneration-Acid Plant—25 miles, truck shipping assumed.

Table A-94. Cooperative Economics—Joint Power-Chemical Company Venture
Nonregulated Chemical Company Portion
Annual Manufacturing Costs for 98% H_2SO_4
from Scrubbed Power Plant Stack Gas[a]
Scheme D—Magnesia Regeneration-Acid Manufacture

(Equivalent to 3000-mw new coal-fired power unit, 3.5% S in fuel; 640,500 tons/yr 100% H_2SO_4)
Magnesium sulfite source—three 1000-mw units

	Annual quantity	Unit cost, $	Total annual cost, $	Cost/ton of acid, $
Direct Costs				
Delivered raw material				
Magnesium sulfite	774,750 tons	28.69/ton	22,227,900	34.704
Shipping cost for magnesium sulfite[c]	774,750 tons	2.40/ton	1,859,400	2.903
Coke	4,440 tons	23.50/ton	104,300	0.163
Catalyst	10,440 liters	1.51/liter	15,800	0.025
Subtotal raw material			24,207,400	37.795
Conversion costs				
Operating labor and supervision	39,200 man-hr	6.00/man-hr	235,200	0.367
Utilities				
Fuel oil	16,740,000 gal	0.09/gal	1,506,600	2.352
Heat credit	65,280 MM Btu	-0.40/MM Btu	(26,100)	(0.041)
Process water	12,004,212 M gal	0.02/M gal[b]	240,000	0.375
Electricity	75,504,000 kwh	0.006/kwh[b]	453,000	0.707
Maintenance				
Labor and material, .03 x 26,096,000			782,900	1.222
Analyses			99,000	0.155
Subtotal conversion costs			3,290,600	5.137
Subtotal direct costs			27,498,000	42.932
Indirect Costs				
Depreciation at 10% of fixed investment			2,609,600	4.074
Local taxes and insurance at 2% of fixed investment			521,900	0.815
Overhead				
Plant, 20% of conversion costs			658,100	1.028
Administrative, research, and service			797,200	1.245
Subtotal indirect costs			4,586,800	7.162
Total annual manufacturing costs for H_2SO_4			32,084,800	50.094

[a] Basis:
Midwest plant location—1972 costs.
Acid plant on-stream time, 8,000 hr/yr.
Acid stack gas reheat to 175° F.
Capital investment, $26,096,000; working capital, $5,314,900.

[b] Cost of utility supplied at full value.

[c] Average shipping distance between Power Plant and Regeneration-Acid Plant—25 miles, truck shipping assumed.

Table A-95

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 200 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 11685000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	45200	5086300	8.00	361600	4724700	4724700	3825400	(899300)	(899300)
2	7000	45200	5005300	8.00	361600	4643700	9368400	3761700	(882000)	(1781300)
3	7000	45200	4924200	8.00	361600	4562600	13931000	3698000	(864600)	(2645900)
4	7000	45200	4843200	8.00	361600	4481600	18412600	3634200	(847400)	(3493300)
5	7000	45200	4762200	8.00	361600	4400600	22813200	3570500	(830100)	(4323400)
6	7000	45200	4681200	8.00	361600	4319600	27132800	3506800	(812800)	(5136200)
7	7000	45200	4600200	8.00	361600	4238600	31371400	3443000	(795600)	(5931800)
8	7000	45200	4519200	8.00	361600	4157600	35529000	3379300	(778300)	(6710100)
9	7000	45200	4438200	8.00	361600	4076600	39605600	3315600	(761000)	(7471100)
10	7000	45200	4357100	8.00	361600	3995500	43601100	3251900	(743600)	(8214700)
11	5000	32300	3809100	5.00	161500	3647600	47248700	2868100	(779500)	(8994200)
12	5000	32300	3728100	5.00	161500	3566600	50815300	2804400	(762200)	(9756400)
13	5000	32300	3647100	5.00	161500	3485600	54300900	2740700	(744900)	(10501300)
14	5000	32300	3566100	5.00	161500	3404600	57705500	2676900	(727700)	(11229000)
15	5000	32300	3485100	5.00	161500	3323600	61029100	2613200	(710400)	(11939400)
16	3500	22600	3027000	5.00	113000	2914000	63943100	2288900	(625100)	(12564500)
17	3500	22600	2946000	5.00	113000	2833000	66776100	2225100	(607900)	(13172400)
18	3500	22600	2865000	5.00	113000	2752000	69528100	2161400	(590600)	(13763000)
19	3500	22600	2784000	5.00	113000	2671000	72199100	2097700	(573300)	(14336300)
20	3500	22600	2703000	5.00	113000	2590000	74789100	2033900	(556100)	(14892400)
21	1500	9700	2047700	5.00	48500	1999200	76788300	1567700	(431500)	(15323900)
22	1500	9700	1966600	5.00	48500	1918100	78706400	1504000	(414100)	(15738000)
23	1500	9700	1885600	5.00	48500	1837100	80543500	1440200	(396900)	(16134900)
24	1500	9700	1804600	5.00	48500	1756100	82299600	1376500	(379600)	(16514500)
25	1500	9700	1723600	5.00	48500	1675100	83974700	1312800	(362300)	(16876800)
26	1500	9700	1642600	5.00	48500	1594100	85568800	1249100	(345000)	(17221800)
27	1500	9700	1561600	5.00	48500	1513100	87081900	1185300	(327800)	(17549600)
28	1500	9700	1480500	5.00	48500	1432000	88513900	1121600	(310400)	(17860000)
29	1500	9700	1399500	5.00	48500	1351000	89864900	1057900	(293100)	(18153100)
30	1500	9700	1318500	5.00	48500	1270000	91134900	994100	(275900)	(18429000)
TOT	127500	823500	96608400		5473500	91134900		72705900	(18429000)	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						9.32		7.44		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						3.57		2.85		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						36354900		29257300	(7097600)	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						3.72		2.99		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						1.43		1.15		

Table A-96

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 200 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 11685000

Includes comparison with projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	45200	5086300	8.00	361600	4724700	4724700	4388700	(336000)	(336000)
2	7000	45200	5005300	8.00	361600	4643700	9368400	4338300	(305400)	(641400)
3	7000	45200	4924200	8.00	361600	4562600	13931000	4288000	(274600)	(916000)
4	7000	45200	4843200	8.00	361600	4481600	18412600	4237700	(243900)	(1159900)
5	7000	45200	4762200	8.00	361600	4400600	22813200	4187300	(213300)	(1373200)
6	7000	45200	4681200	8.00	361600	4319600	27132800	4137000	(182600)	(1555800)
7	7000	45200	4600200	8.00	361600	4238600	31371400	4086700	(151900)	(1707700)
8	7000	45200	4519200	8.00	361600	4157600	35529000	4036300	(121300)	(1829000)
9	7000	45200	4438200	8.00	361600	4076600	39605600	3986000	(90600)	(1919600)
10	7000	45200	4357100	8.00	361600	3995500	43601100	3935700	(59800)	(1979400)
11	5000	32300	3809100	5.00	161500	3647600	47248700	3252900	(394700)	(2374100)
12	5000	32300	3728100	5.00	161500	3566600	50815300	3202600	(364000)	(2738100)
13	5000	32300	3647100	5.00	161500	3485600	54300900	3152200	(333400)	(3071500)
14	5000	32300	3566100	5.00	161500	3404600	57705500	3101900	(302700)	(3374200)
15	5000	32300	3485100	5.00	161500	3323600	61029100	3051600	(272000)	(3646200)
16	3500	22600	3027000	5.00	113000	2914000	63943100	2508100	(405900)	(4052100)
17	3500	22600	2946000	5.00	113000	2833000	66776100	2457800	(375200)	(4427300)
18	3500	22600	2865000	5.00	113000	2752000	69528100	2407500	(344500)	(4771800)
19	3500	22600	2784000	5.00	113000	2671000	72199100	2357100	(313900)	(5085700)
20	3500	22600	2703000	5.00	113000	2590000	74789100	2306800	(283200)	(5368900)
21	1500	9700	2047700	5.00	48500	1999200	76788300	1550300	(448900)	(5817800)
22	1500	9700	1966600	5.00	48500	1918100	78706400	1499900	(418200)	(6236000)
23	1500	9700	1885600	5.00	48500	1837100	80543500	1449600	(387500)	(6623500)
24	1500	9700	1804600	5.00	48500	1756100	82299600	1399300	(356800)	(6980300)
25	1500	9700	1723600	5.00	48500	1675100	83974700	1348900	(326200)	(7306500)
26	1500	9700	1642600	5.00	48500	1594100	85568800	1298600	(295500)	(7602000)
27	1500	9700	1561600	5.00	48500	1513100	87081900	1248200	(264900)	(7866900)
28	1500	9700	1480500	5.00	48500	1432000	88513900	1197900	(234100)	(8101000)
29	1500	9700	1399500	5.00	48500	1351000	89864900	1147600	(203400)	(8304400)
30	1500	9700	1318500	5.00	48500	1270000	91134900	1097200	(172800)	(8477200)
TOT	127500	823500	96608400		5473500	91134900		82657700	(8477200)	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						9.32		8.46		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						3.57		3.24		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						36354900		33873300	(2481600)	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						3.72		3.47		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						1.43		1.33		

Table A-97

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 200 MW. EXISTING COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 13083000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1										
2										
3										
4										
5										
6										
7										
8										
9	7000	46600	5657300	8.00	372800	5284500	5284500	4276000	(1008500)	(1008500)
10	7000	46600	5533600	8.00	372800	5160800	10445300	4179500	(981300)	(1989800)
11	5000	33300	4923700	8.00	266400	4657300	15102600	3741100	(916200)	(2906000)
12	5000	33300	4800000	8.00	266400	4533600	19636200	3644600	(889000)	(3795000)
13	5000	33300	4676300	8.00	266400	4409900	24046100	3548100	(861800)	(4656800)
14	5000	33300	4552600	8.00	266400	4286200	28332300	3451600	(834600)	(5491400)
15	5000	33300	4428900	8.00	266400	4162500	32494800	3355100	(807400)	(6298800)
16	3500	23300	3911100	8.00	186400	3724700	36219500	2979200	(745500)	(7044300)
17	3500	23300	3787400	8.00	186400	3601000	39820500	2882700	(718300)	(7762600)
18	3500	23300	3663700	8.00	186400	3477300	43297800	2786200	(691100)	(8453700)
19	3500	23300	3540000	5.00	116500	3423500	46721300	2689700	(733800)	(9187500)
20	3500	23300	3416300	5.00	116500	3299800	50021100	2593100	(706700)	(9894200)
21	1500	10000	2688800	5.00	50000	2638800	52659900	2064200	(574600)	(10468800)
22	1500	10000	2565100	5.00	50000	2515100	55175000	1967700	(547400)	(11016200)
23	1500	10000	2441400	5.00	50000	2391400	57566400	1871200	(520200)	(11536400)
24	1500	10000	2317700	5.00	50000	2267700	59834100	1774700	(493000)	(12029400)
25	1500	10000	2194000	5.00	50000	2144000	61978100	1678200	(465800)	(12495200)
26	1500	10000	2070300	5.00	50000	2020300	63998400	1581700	(438600)	(12933800)
27	1500	10000	1946600	5.00	50000	1896600	65895000	1485200	(411400)	(13345200)
28	1500	10000	1822900	5.00	50000	1772900	67667900	1388600	(384300)	(13729500)
29	1500	10000	1699200	5.00	50000	1649200	69317100	1292100	(357100)	(14086600)
30	1500	10000	1575500	5.00	50000	1525500	70842600	1195600	(329900)	(14416500)
TOT	71500	476200	74212400		3369800	70842600		56426100	(14416500)	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						12.52		9.97		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						4.95		3.95		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						34079300		27307600	(6771700)	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						6.02		4.82		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						2.38		1.91		

Table A-98

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 500 MW. NEW COAL FIRED POWER PLANT, 2.0 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 18788000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	63100	7868500	8.00	504800	7363700	7363700	6483500	(880200)	(880200)
2	7000	63100	7738200	8.00	504800	7233400	14597100	6371300	(862100)	(1742300)
3	7000	63100	7608000	8.00	504800	7103200	21700300	6259200	(844000)	(2586300)
4	7000	63100	7477700	8.00	504800	6972900	28673200	6147100	(825800)	(3412100)
5	7000	63100	7347400	8.00	504800	6842600	35515800	6034900	(807700)	(4219800)
6	7000	63100	7217200	8.00	504800	6712400	42228200	5922800	(789600)	(5009400)
7	7000	63100	7086900	8.00	504800	6582100	48810300	5810700	(771400)	(5780800)
8	7000	63100	6956600	8.00	504800	6451800	55262100	5698500	(753300)	(6534100)
9	7000	63100	6826300	8.00	504800	6321500	61583600	5586400	(735100)	(7269200)
10	7000	63100	6696100	8.00	504800	6191300	67774900	5474300	(717000)	(7986200)
11	5000	45100	5861400	5.00	225500	5635900	73410800	4840900	(795000)	(8781200)
12	5000	45100	5731100	5.00	225500	5505600	78916400	4728800	(776800)	(9558000)
13	5000	45100	5600900	5.00	225500	5375400	84291800	4616700	(758700)	(10316700)
14	5000	45100	5470600	5.00	225500	5245100	89536900	4504500	(740600)	(11057300)
15	5000	45100	5340300	5.00	225500	5114800	94651700	4392400	(722400)	(11779700)
16	3500	31600	4645900	5.00	158000	4487900	99139600	3858100	(629800)	(12409500)
17	3500	31600	4515700	5.00	158000	4357700	103497300	3746000	(611700)	(13021200)
18	3500	31600	4385400	5.00	158000	4227400	107724700	3633800	(593600)	(13614800)
19	3500	31600	4255100	5.00	158000	4097100	111821800	3521700	(575400)	(14190200)
20	3500	31600	4124900	5.00	158000	3966900	115788700	3409600	(557300)	(14747500)
21	1500	13500	3149000	5.00	67500	3081500	118870200	2651800	(429700)	(15177200)
22	1500	13500	3018700	5.00	67500	2951200	121821400	2539700	(411500)	(15588700)
23	1500	13500	2888500	5.00	67500	2821000	124642400	2427600	(393400)	(15982100)
24	1500	13500	2758200	5.00	67500	2690700	127333100	2315400	(375300)	(16357400)
25	1500	13500	2627900	5.00	67500	2560400	129893500	2203300	(357100)	(16714500)
26	1500	13500	2497600	5.00	67500	2430100	132323600	2091200	(338900)	(17053400)
27	1500	13500	2367400	5.00	67500	2299900	134623500	1979000	(320900)	(17374300)
28	1500	13500	2237100	5.00	67500	2169600	136793100	1866900	(302700)	(17677000)
29	1500	13500	2106800	5.00	67500	2039300	138832400	1754800	(284500)	(17961500)
30	1500	13500	1976600	5.00	67500	1909100	140741500	1642600	(266500)	(18228000)
TOT	127500	1149500	148382000		7640500	140741500		122513500	(18228000)	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						5.89		5.12		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						2.21		1.92		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						56387000		49407100	(6979900)	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						2.36		2.07		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.88		0.78		

Table A-88

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 500 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 21732000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	110400	9309800	8.00	883200	8426600	8426600	7209600	(1217000)	(1217000)
2	7000	110400	9159100	8.00	883200	8275900	16702500	7087400	(1188500)	(2405500)
3	7000	110400	9008400	8.00	883200	8125200	24827700	6965200	(1160000)	(3565500)
4	7000	110400	8857700	8.00	883200	7974500	32802200	6843000	(1131500)	(4697000)
5	7000	110400	8707100	8.00	883200	7823900	40626100	6720900	(1103000)	(5800000)
6	7000	110400	8556400	8.00	883200	7673200	48299300	6598700	(1074500)	(6874500)
7	7000	110400	8405700	8.00	883200	7522500	55821800	6476500	(1046000)	(7920500)
8	7000	110400	8255000	8.00	883200	7371800	63193600	6354300	(1017500)	(8938000)
9	7000	110400	8104400	8.00	883200	7221200	70414800	6232100	(989100)	(9927100)
10	7000	110400	7953700	8.00	883200	7070500	77485300	6110000	(960500)	(10887600)
11	5000	78900	6930400	5.00	394500	6535900	84021200	5381100	(1154800)	(12042400)
12	5000	78900	6779700	5.00	394500	6385200	90406400	5258900	(1126300)	(13168700)
13	5000	78900	6629100	5.00	394500	6234600	96641000	5136700	(1097900)	(14266600)
14	5000	78900	6478400	5.00	394500	6083900	102724900	5014500	(1069400)	(15336000)
15	5000	78900	6327700	5.00	394500	5933200	108658100	4892400	(1040800)	(16374800)
16	3500	55200	5481000	5.00	276000	5205000	113863100	4280700	(924300)	(17301100)
17	3500	55200	5330400	5.00	276000	5054400	118917500	4158500	(895900)	(18197000)
18	3500	55200	5179700	5.00	276000	4903700	123821200	4036300	(867400)	(19064400)
19	3500	55200	5029000	5.00	276000	4753000	128574200	3914200	(838800)	(19903200)
20	3500	55200	4878300	5.00	276000	4602300	133176500	3792000	(810300)	(20713500)
21	1500	23700	3690600	5.00	118500	3572100	136748600	2926100	(646000)	(21359500)
22	1500	23700	3539900	5.00	118500	3421400	140170000	2803900	(617500)	(21977000)
23	1500	23700	3389200	5.00	118500	3270700	143440700	2681700	(589000)	(22566000)
24	1500	23700	3238500	5.00	118500	3120000	146560700	2559600	(560400)	(23126400)
25	1500	23700	3087900	5.00	118500	2969400	149530100	2437400	(532000)	(23658400)
26	1500	23700	2937200	5.00	118500	2818700	152348800	2315200	(503500)	(24161900)
27	1500	23700	2786500	5.00	118500	2668000	155016800	2193000	(475000)	(24636900)
28	1500	23700	2635800	5.00	118500	2517300	157534100	2070800	(446500)	(25083400)
29	1500	23700	2485200	5.00	118500	2366700	159900800	1948700	(418000)	(25501400)
30	1500	23700	2334500	5.00	18500	2216000	162116800	1826500	(389500)	(25890900)
TOT	127500	2011500	175486300		13369500	162116800		136225900	(25890900)	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						6.78		5.70		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						2.54		2.14		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						64708000		54984900	(9723100)	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						2.71		2.30		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						1.02		0.86		

Table A-100

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 500 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 21732000

Includes comparison with projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/ KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	110400	9309800	8.00	883200	8426600	8426600	9115900	689300	689300
2	7000	110400	9159100	8.00	883200	8275900	16702500	9016300	740400	1429700
3	7000	110400	9008400	8.00	883200	8125200	24827700	8916700	791500	2221200
4	7000	110400	8857700	8.00	883200	7974500	32802200	8817100	842600	3063800
5	7000	110400	8707100	8.00	883200	7823900	40626100	8717600	893700	3957500
6	7000	110400	8556400	8.00	883200	7673200	48299300	8618000	944800	4902300
7	7000	110400	8405700	8.00	883200	7522500	55821800	8518400	995900	5898200
8	7000	110400	8255000	8.00	883200	7371800	63193600	8418800	1047000	6945200
9	7000	110400	8104400	8.00	883200	7221200	70414800	8319200	1098000	8043200
10	7000	110400	7953700	8.00	883200	7070500	77485300	8219600	1149100	9192300
11	5000	78900	6930400	5.00	394500	6535900	84021200	6719600	183700	9376000
12	5000	78900	6779700	5.00	394500	6385200	90406400	6620000	234800	9610800
13	5000	78900	6629100	5.00	394500	6234600	96641000	6520400	285800	9896600
14	5000	78900	6478400	5.00	394500	6083900	102724900	6420800	336900	10233500
15	5000	78900	6327700	5.00	394500	5933200	108658100	6321200	388000	10621500
16	3500	55200	5481000	5.00	276000	5205000	113863100	5139500	(65500)	10556000
17	3500	55200	5330400	5.00	276000	5054400	118917500	5039900	(14500)	10541500
18	3500	55200	5179700	5.00	276000	4903700	123821200	4940300	36600	10578100
19	3500	55200	5029000	5.00	276000	4753000	128574200	4840700	87700	10665800
20	3500	55200	4878300	5.00	276000	4602300	133176500	4741100	138800	10804600
21	1500	23700	3690600	5.00	118500	3572100	136748600	3114300	(457800)	10346800
22	1500	23700	3539900	5.00	118500	3421400	140170000	3014700	(406700)	9940100
23	1500	23700	3389200	5.00	118500	3270700	143440700	2915100	(355600)	9584300
24	1500	23700	3238500	5.00	118500	3120000	146560700	2815500	(304500)	9280000
25	1500	23700	3087900	5.00	118500	2969600	149530100	2715900	(253500)	9026500
26	1500	23700	2937200	5.00	118500	2818700	152348800	2616400	(202300)	8824200
27	1500	23700	2786500	5.00	118500	2668000	155016800	2516800	(151200)	8673000
28	1500	23700	2635800	5.00	118500	2517300	157534100	2417200	(100100)	8572900
29	1500	23700	2485200	5.00	118500	2366700	159900800	2317600	(49100)	8523800
30	1500	23700	2334500	5.00	118500	2216000	162116800	2218000	2000	8525800
TOT	127500	2011500	175486300		13369500	162116800		170642600	8525800	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						6.78		7.14		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						2.54		2.68		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						64708000		70296800	5588800	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						2.71		2.94		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						1.02		1.10		

Table A-101

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 500 MW. NEW COAL FIRED POWER PLANT, 5.0 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 24275000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	157800	10592000	8.00	1262400	9329600	9329600	7863100	(1466500)	(1466500)
2	7000	157800	10423700	8.00	1262400	9161300	18490900	7731900	(1429400)	(2895900)
3	7000	157800	10255400	8.00	1262400	8993000	27483900	7600700	(1392300)	(4288200)
4	7000	157800	10087100	8.00	1262400	8824700	36308600	7469400	(1355300)	(5643500)
5	7000	157800	9918700	8.00	1262400	8656300	44964900	7338200	(1318100)	(6961600)
6	7000	157800	9750400	8.00	1262400	8488000	53452900	7207000	(1281000)	(8242600)
7	7000	157900	9582100	8.00	1262400	8319700	61772600	7075800	(1243900)	(9486500)
8	7000	157800	9413800	8.00	1262400	8151400	69924000	6944500	(1206900)	(10693400)
9	7000	157800	9245500	8.00	1262400	7983100	77907100	6813300	(1169800)	(11863200)
10	7000	157800	9077200	8.00	1262400	7814800	85721900	6682100	(1132700)	(12995900)
11	5000	112700	7881000	5.00	563500	7317500	93039400	5865300	(1452200)	(14448100)
12	5000	112700	7712700	5.00	563500	7149200	100188600	5734000	(1415200)	(15863300)
13	5000	112700	7544300	5.00	563500	6980800	107169400	5602800	(1378000)	(17241300)
14	5000	112700	7376000	5.00	563500	6812500	113981900	5471600	(1340900)	(18582200)
15	5000	112700	7207700	5.00	563500	6644200	120626100	5340300	(1303900)	(19886100)
16	3500	78900	6221800	5.00	394500	5827300	126453400	4657600	(1169700)	(21055800)
17	3500	78900	6053500	5.00	394500	5659000	132112400	4526400	(1132600)	(22188400)
18	3500	78900	5885200	5.00	394500	5490700	137603100	4395200	(1095500)	(23283900)
19	3500	78900	5716900	5.00	394500	5322400	142925500	4263900	(1058500)	(24342400)
20	3500	78900	5548500	5.00	394500	5154000	148079500	4132700	(1021300)	(25363700)
21	1500	33800	4167600	5.00	169000	3998600	152078100	3168900	(829700)	(26193400)
22	1500	33800	3999300	5.00	169000	3830300	155908400	3037700	(792600)	(26986000)
23	1500	33800	3831000	5.00	169000	3662000	159570400	2906400	(755600)	(27741600)
24	1500	33800	3662700	5.00	169000	3493700	163064100	2775200	(718500)	(28460100)
25	1500	33800	3494400	5.00	169000	3325400	166389500	2644000	(681400)	(29141500)
26	1500	33800	3326100	5.00	169000	3157100	169546600	2512700	(644400)	(29785900)
27	1500	33800	3157700	5.00	169000	2988700	172535300	2381500	(607200)	(30393100)
28	1500	33800	2989400	5.00	169000	2820400	175355700	2250300	(570100)	(30963200)
29	1500	33800	2821100	5.00	169000	2652100	178007800	2119100	(533000)	(31496200)
30	1500	33800	2652800	5.00	169000	2483800	180491600	1987800	(496000)	(31992200)
TOT	127500	2874000	199595600		19104000	180491600		148499400	(31992200)	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						7.55		6.21		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						2.83		2.33		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						71813900		59995400	(11818500)	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						3.00		2.51		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						1.13		0.94		

Table A-102

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 500 MW. EXISTING COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 24646000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1										
2										
3										
4	7000	112900	10326700	8.00	903200	9423500	9423500	7979600	(1443900)	(1443900)
5	7000	112900	10136800	8.00	903200	9233600	18657100	7827600	(1406000)	(2849900)
6	7000	112900	9946900	8.00	903200	9043700	27700800	7675700	(1368000)	(4217900)
7	7000	112900	9757100	8.00	903200	8853900	36554700	7523800	(1330100)	(5548000)
8	7000	112900	9567200	8.00	903200	8664000	45218700	7371900	(1292100)	(6840100)
9	7000	112900	9377400	8.00	903200	8474200	53692900	7220000	(1254200)	(8094300)
10	7000	112900	9187500	8.00	903200	8284300	61977200	7068000	(1216300)	(9310600)
11	5000	80600	8083000	8.00	644800	7438200	69415400	6270500	(1167700)	(10478300)
12	5000	80600	7893200	8.00	644800	7248400	76663800	6118600	(1129800)	(11608100)
13	5000	80600	7703300	8.00	644800	7058500	83722300	5966700	(1091800)	(12699900)
14	5000	80600	7513400	5.00	403000	7110400	90832700	5814700	(1295700)	(13995600)
15	5000	80600	7323600	5.00	403000	6920600	97753300	5662800	(1257800)	(15253400)
16	3500	56400	6400900	5.00	282000	6118900	103872200	4988600	(1130300)	(16383700)
17	3500	56400	6211100	5.00	282000	5929100	109801300	4836700	(1092400)	(17476100)
18	3500	56400	6021200	5.00	282000	5739200	115540500	4684700	(1054500)	(18530600)
19	3500	56400	5831300	5.00	282000	5549300	121089800	4532800	(1016500)	(19547100)
20	3500	56400	5641500	5.00	282000	5359500	126449300	4380900	(978600)	(20525700)
21	1500	24200	4354100	5.00	121000	4233100	130682400	3432400	(800700)	(21326400)
22	1500	24200	4164200	5.00	121000	4043200	134725600	3280500	(762700)	(22089100)
23	1500	24200	3974400	5.00	121000	3853400	138579000	3128500	(724900)	(22814000)
24	1500	24200	3784500	5.00	121000	3663500	142242500	2976600	(686900)	(23500900)
25	1500	24200	3594700	5.00	121000	3473700	145716200	2824700	(649000)	(24149900)
26	1500	24200	3404800	5.00	121000	3283800	149000000	2672800	(611000)	(24760900)
27	1500	24200	3214900	5.00	121000	3093900	152093900	2520800	(573100)	(25334000)
28	1500	24200	3025100	5.00	121000	2904100	154998000	2368900	(535200)	(25869200)
29	1500	24200	2835200	5.00	121000	2714200	157712200	2217000	(497200)	(26366400)
30	1500	24200	2645300	5.00	121000	2524300	160236500	2065100	(459200)	(26825600)
TOT	106500	1717300	171919300		11692800	160236500		133410900	(26825600)	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						7.85		6.54		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						3.01		2.51		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						68678700		57749700	(10929000)	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						3.36		2.83		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						1.29		1.08		

Table A-103

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 1000 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 33118000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	213500	14080700	8.00	1708000	12372700	12372700	11082800	(1289900)	(1289900)
2	7000	213500	13851100	8.00	1708000	12143100	24515800	10892700	(1250400)	(2540300)
3	7000	213500	13621500	8.00	1708000	11913500	36429300	10702700	(1210800)	(3751100)
4	7000	213500	13391900	8.00	1708000	11683900	48113200	10512600	(1171300)	(4922400)
5	7000	213500	13162300	8.00	1708000	11454300	59567500	10322500	(1131800)	(6054200)
6	7000	213500	12932700	8.00	1708000	11224700	70792200	10132500	(1092200)	(7146400)
7	7000	213500	12703100	8.00	1708000	10995100	81787300	9942400	(1052700)	(8199100)
8	7000	213500	12473500	8.00	1708000	10765500	92552800	9752300	(1013200)	(9212300)
9	7000	213500	12243900	8.00	1708000	10535900	103088700	9562200	(973700)	(10186000)
10	7000	213500	12014200	8.00	1708000	10306200	113394900	9372200	(934000)	(11120000)
11	5000	152500	10428600	5.00	762500	9666100	123061000	8236300	(1429800)	(12549800)
12	5000	152500	10199000	5.00	762500	9436500	132497500	8046200	(1390300)	(13940100)
13	5000	152500	9969400	5.00	762500	9206900	141704400	7856200	(1350700)	(15290800)
14	5000	152500	9739800	5.00	762500	8977300	150681700	7666100	(1311200)	(16602000)
15	5000	152500	9510200	5.00	762500	8747700	159429400	7476000	(1271700)	(17873700)
16	3500	106800	8210800	5.00	534000	7676800	167106200	6530600	(1146200)	(19019900)
17	3500	106800	7981200	5.00	534000	7447200	174553400	6340600	(1106600)	(20126500)
18	3500	106800	7751600	5.00	534000	7217600	181771000	6150500	(1067100)	(21193600)
19	3500	106800	7521900	5.00	534000	6987900	188758900	5960400	(1027500)	(22221100)
20	3500	106800	7292300	5.00	534000	6758300	195517200	5770400	(987900)	(23209000)
21	1500	45800	5499000	5.00	229000	5270000	200787200	4451700	(818300)	(24027300)
22	1500	45800	5269400	5.00	229000	5040400	205827600	4261600	(778800)	(24806100)
23	1500	45800	5039800	5.00	229000	4810800	210638400	4071600	(739200)	(25545300)
24	1500	45800	4810200	5.00	229000	4581200	215219600	3881500	(699700)	(26245000)
25	1500	45800	4580600	5.00	229000	4351600	219571200	3691400	(660200)	(26905200)
26	1500	45800	4351000	5.00	229000	4122000	223693200	3501300	(620700)	(27525900)
27	1500	45800	4121400	5.00	229000	3892400	227585600	3311300	(581100)	(28107000)
28	1500	45800	3891700	5.00	229000	3662700	231248300	3121200	(541500)	(28648500)
29	1500	45800	3662100	5.00	229000	3433100	234681400	2931100	(502000)	(29150500)
30	1500	45800	3432500	5.00	229000	3203500	237884900	2741100	(462400)	(29612900)
TOT	127500	3889500	263737400		25852500	237884900		208272000	(29612900)	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						5.15		4.51		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						1.87		1.63		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						94910200		84316100	(10594100)	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						2.05		1.82		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.74		0.66		

Table A-104

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 1000 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 33118000

Includes comparison with projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	213500	14080700	8.00	1708000	12372700	12372700	15208800	2836100	2836100
2	7000	213500	13851100	8.00	1708000	12143100	24515800	15053700	2910600	5746700
3	7000	213500	13621500	8.00	1708000	11913500	36429300	14898600	2985100	8731800
4	7000	213500	13391900	8.00	1708000	11683900	48113200	14743500	3059600	11791400
5	7000	213500	13162300	8.00	1708000	11454300	59567500	14588400	3134100	14925500
6	7000	213500	12932700	8.00	1708000	11224700	70792200	14433200	3208500	18134000
7	7000	213500	12703100	8.00	1708000	10995100	81787300	14278100	3283000	21417000
8	7000	213500	12473500	8.00	1708000	10765500	92552800	14123000	3357500	24774500
9	7000	213500	12243900	8.00	1708000	10535900	103088700	13967900	3432000	28206500
10	7000	213500	12014200	8.00	1708000	10306200	113394900	13812800	3506600	31713100
11	5000	152500	10428600	5.00	762500	9666100	123061000	11154900	1488800	33201900
12	5000	152500	10199000	5.00	762500	9436500	132497500	10999800	1563300	34765200
13	5000	152500	9969400	5.00	762500	9206900	141704400	10844700	1637800	36403000
14	5000	152500	9739800	5.00	762500	8977300	150681700	10689600	1712300	38115300
15	5000	152500	9510200	5.00	762500	8747700	159429400	10534500	1786800	39902100
16	3500	106800	8210800	5.00	534000	7676800	167106200	8458700	781900	40684000
17	3500	106800	7981200	5.00	534000	7447200	174553400	8303600	856400	41540400
18	3500	106800	7751600	5.00	534000	7217600	181771000	8148500	930900	42471300
19	3500	106800	7521900	5.00	534000	6987900	188758900	7993400	1005500	43476800
20	3500	106800	7292300	5.00	534000	6758300	195517200	7838300	1080000	44556800
21	1500	45800	5499000	5.00	229000	5270000	200787200	5007900	(262100)	44294700
22	1500	45800	5269400	5.00	229000	5040400	205827600	4852800	(187600)	44107100
23	1500	45800	5039800	5.00	229000	4810800	210638400	4697700	(113100)	43994000
24	1500	45800	4810200	5.00	229000	4581200	215219600	4542500	(38700)	43955300
25	1500	45800	4580600	5.00	229000	4351600	219571200	4387400	35800	43991100
26	1500	45800	4351000	5.00	229000	4122000	223693200	4232300	110300	44101400
27	1500	45800	4121400	5.00	229000	3892400	227585600	4077200	184800	44286200
28	1500	45800	3891700	5.00	229000	3662700	231248300	3922100	259400	44545600
29	1500	45800	3662100	5.00	229000	3433100	234681400	3767000	333900	44879500
30	1500	45800	3432500	5.00	229000	3203500	237884900	3611900	408400	45287900
TOT	127500	3389500	263737400		25852500	237884900		283172800	45287900	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						5.15		6.13		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						1.87		2.22		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						94910200		117261000	22350800	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						2.05		2.54		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.74		0.92		

Table A-105

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 1000 MW. EXISTING COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 36634000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1										
2										
3										
4	7000	220900	15306000	8.00	1767200	13538800	13538800	12063000	(1475800)	(1475800)
5	7000	220900	15023800	8.00	1767200	13256600	26795400	11834900	(1421700)	(2897500)
6	7000	220900	14741500	8.00	1767200	12974300	39769700	11606700	(1367600)	(4265100)
7	7000	220900	14459300	8.00	1767200	12692100	52461800	11378600	(1313500)	(5578600)
8	7000	220900	14177100	8.00	1767200	12409900	64871700	11150400	(1259500)	(6838100)
9	7000	220900	13894900	8.00	1767200	12127700	76999400	10922200	(1205500)	(8043600)
10	7000	220900	13612700	8.00	1767200	11845500	88844900	10694100	(1151400)	(9195000)
11	5000	157800	11923100	8.00	1262400	10660700	99505600	9432700	(1228000)	(10423000)
12	5000	157800	11640900	8.00	1262400	10378500	109884100	9204600	(1173900)	(11596900)
13	5000	157800	11358600	8.00	1262400	10096200	119980300	8976400	(1119800)	(12716700)
14	5000	157800	11076400	5.00	789000	10287400	130267700	8748300	(1539100)	(14255800)
15	5000	157800	10794200	5.00	789000	10005200	140272900	8520100	(1485100)	(15740900)
16	3500	110400	9399100	5.00	552000	8847100	149120000	7467500	(1379600)	(17120500)
17	3500	110400	9116900	5.00	552000	8564900	157684900	7239300	(1325600)	(18446100)
18	3500	110400	8834700	5.00	552000	8282700	165967600	7011100	(1271600)	(19717700)
19	3500	110400	8552500	5.00	552000	8000500	173968100	6783000	(1217500)	(20935200)
20	3500	110400	8270200	5.00	552000	7718200	181686300	6554800	(1163400)	(22098600)
21	1500	47300	6354900	5.00	236500	6118400	187804700	5098000	(1020400)	(23119000)
22	1500	47300	6072700	5.00	236500	5836200	193640900	4869800	(966400)	(24085400)
23	1500	47300	5790500	5.00	236500	5554000	199194900	4641700	(912300)	(24997700)
24	1500	47300	5508300	5.00	236500	5271800	204466700	4413500	(858300)	(25856000)
25	1500	47300	5226100	5.00	236500	4989600	209456300	4185400	(804200)	(26660200)
26	1500	47300	4943900	5.00	236500	4707400	214163700	3957200	(750200)	(27410400)
27	1500	47300	4661600	5.00	236500	4425100	218588800	3729100	(696000)	(28106400)
28	1500	47300	4379400	5.00	236500	4142900	222731700	3500900	(642000)	(28748400)
29	1500	47300	4097200	5.00	236500	3860700	226592400	3272700	(588000)	(29336400)
30	1500	47300	3815000	5.00	236500	3578500	230170900	3044600	(533900)	(29870300)
TOT	106500	3360300	253031500		22860600	230170900		200300600	(29870300)	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						5.76		5.02		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						2.16		1.88		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						98600300		87046700	(11553600)	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						2.47		2.18		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.93		0.82		

Table A-106

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 200 MW. NEW OIL FIRED POWER PLANT, 1.0 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 5148000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	9600	2260900	8.00	76800	2184100	2184100	2114800	(69300)	(69300)
2	7000	9600	2225200	8.00	76800	2148400	4332500	2080300	(68100)	(137400)
3	7000	9600	2189500	8.00	76800	2112700	6445200	2045800	(66900)	(204300)
4	7000	9600	2153800	8.00	76800	2077000	8522200	2011300	(65700)	(270000)
5	7000	9600	2118100	8.00	76800	2041300	10563500	1976700	(65600)	(335600)
6	7000	9600	2082400	8.00	76800	2005600	12569100	1942200	(63400)	(398000)
7	7000	9600	2046700	8.00	76800	1969900	14539000	1907700	(62200)	(460200)
8	7000	9600	2011000	8.00	76800	1934200	16473200	1873200	(61000)	(521200)
9	7000	9600	1975300	8.00	76800	1898500	18371700	1838600	(59900)	(581100)
10	7000	9600	1939600	8.00	76800	1862800	20234500	1804100	(58700)	(639800)
11	5000	6900	1701200	5.00	34500	1666700	21901200	1592500	(74200)	(714000)
12	5000	6900	1665500	5.00	34500	1631000	23532200	1557900	(73100)	(787100)
13	5000	6900	1629800	5.00	34500	1595300	25127500	1523400	(71900)	(859000)
14	5000	6900	1594100	5.00	34500	1559600	26687100	1488900	(70700)	(929700)
15	5000	6900	1558400	5.00	34500	1523900	28211000	1454400	(69500)	(999200)
16	3500	4800	1356800	5.00	24000	1332800	29543800	1274200	(58600)	(1057800)
17	3500	4900	1321100	5.00	24000	1297100	30840900	1239700	(57400)	(1115200)
18	3500	4800	1285400	5.00	24000	1261400	32102300	1205200	(56200)	(1171400)
19	3500	4800	1249700	5.00	24000	1225700	33328000	1170600	(55100)	(1226500)
20	3500	4800	1214000	5.00	24000	1190000	34518000	1136100	(53900)	(1280400)
21	1500	2100	922600	5.00	10500	912100	35430100	874300	(37800)	(1318200)
22	1500	2100	886900	5.00	10500	876400	36306500	839800	(36600)	(1354800)
23	1500	2100	851200	5.00	10500	840700	37147200	805200	(35500)	(1390300)
24	1500	2100	815500	5.00	10500	805000	37952200	770700	(34300)	(1424600)
25	1500	2100	779900	5.00	10500	769400	38721600	736200	(33200)	(1457800)
26	1500	2100	744200	5.00	10500	733700	39455300	701600	(32100)	(1489900)
27	1500	2100	708500	5.00	10500	698000	40153300	667100	(30900)	(1520800)
28	1500	2100	672800	5.00	10500	662300	40815600	632600	(29700)	(1550500)
29	1500	2100	637100	5.00	10500	626600	41442200	598100	(28500)	(1579000)
30	1500	2100	601400	5.00	10500	590900	42033100	563500	(27400)	(1606400)
TOT	127500	175500	43198600		1165500	42033100		40426700	(1606400)	
EQUIVALENT COST, DOLLARS PER BARREL OF OIL BURNED						1.12		1.08		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						1.65		1.59		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						16807100		16221100	(586000)	
EQUIVALENT PRESENT WORTH, DOLLARS PER BARREL OF OIL BURNED						0.45		0.43		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.66		0.64		

Table A-107

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 200 MW. NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 6690000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	24100	3001600	8.00	192800	2808800	2808800	2429700	(379100)	(379100)
2	7000	24100	2955200	8.00	192800	2762400	5571200	2390200	(372200)	(751300)
3	7000	24100	2908900	8.00	192800	2716100	8287300	2350700	(365400)	(1116700)
4	7000	24100	2862500	8.00	192800	2669700	10957000	2311100	(358600)	(1475300)
5	7000	24100	2816100	8.00	192800	2623300	13580300	2271600	(351700)	(1827000)
6	7000	24100	2769700	8.00	192800	2576900	16157200	2232100	(344800)	(2171800)
7	7000	24100	2723300	8.00	192800	2530500	18687700	2192600	(337900)	(2509700)
8	7000	24100	2676900	8.00	192800	2484100	21171800	2153100	(331000)	(2840700)
9	7000	24100	2630500	8.00	192800	2437700	23609500	2113500	(324200)	(3164900)
10	7000	24100	2584200	8.00	192800	2391400	26000900	2074000	(317400)	(3482300)
11	5000	17200	2256000	5.00	86000	2170000	28170900	1826600	(343400)	(3825700)
12	5000	17200	2209600	5.00	86000	2123600	30294500	1787100	(336500)	(4162200)
13	5000	17200	2163200	5.00	86000	2077200	32371700	1747600	(329600)	(4491800)
14	5000	17200	2116800	5.00	86000	2030800	34402500	1708000	(322800)	(4814600)
15	5000	17200	2070400	5.00	86000	1984400	36386900	1668500	(315900)	(5130500)
16	3500	12000	1795600	5.00	60000	1735600	38122500	1459000	(276600)	(5407100)
17	3500	12000	1749200	5.00	60000	1689200	39811700	1419500	(269700)	(5676800)
18	3500	12000	1702800	5.00	60000	1642800	41454500	1380000	(262800)	(5939600)
19	3500	12000	1656400	5.00	60000	1596400	43050900	1340400	(256000)	(6195600)
20	3500	12000	1610000	5.00	60000	1550000	44600900	1300900	(249100)	(6444700)
21	1500	5200	1212800	5.00	26000	1186800	45787700	997500	(189300)	(6634000)
22	1500	5200	1166500	5.00	26000	1140500	46928200	958000	(182500)	(6816500)
23	1500	5200	1120100	5.00	26000	1094100	48022300	918500	(175600)	(6992100)
24	1500	5200	1073700	5.00	26000	1047700	49070000	878900	(168800)	(7160900)
25	1500	5200	1027300	5.00	26000	1001300	50071300	839400	(161900)	(7322800)
26	1500	5200	980900	5.00	26000	954900	51026200	799900	(155000)	(7477800)
27	1500	5200	934500	5.00	26000	908500	51934700	760400	(148100)	(7625900)
28	1500	5200	888200	5.00	26000	862200	52796900	720900	(141300)	(7767200)
29	1500	5200	841800	5.00	26000	815800	53612700	681300	(134500)	(7901700)
30	1500	5200	795400	5.00	26000	769400	54382100	641800	(127600)	(8029300)
TOT	127500	439000	57300100		2918000	54382100		46352800	(8029300)	
EQUIVALENT COST, DOLLARS PER BARREL OF OIL BURNED						1.45		1.24		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						2.13		1.82		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						21670900		18625500	(3045400)	
EQUIVALENT PRESENT WORTH, DOLLARS PER BARREL OF OIL BURNED						0.58		0.50		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.85		0.73		

Table A-108

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 200 MW. NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 6690000

Includes comparison with projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	24100	3001600	8.00	192800	2808800	2808800	2514300	(294500)	(294500)
2	7000	24100	2955200	8.00	192800	2762400	5571200	2483200	(279200)	(573700)
3	7000	24100	2908900	8.00	192800	2716100	8287300	2452000	(264100)	(837800)
4	7000	24100	2862500	8.00	192800	2669700	10957000	2420900	(248800)	(1086600)
5	7000	24100	2816100	8.00	192800	2623300	13580300	2389700	(233600)	(1320200)
6	7000	24100	2769700	8.00	192800	2576900	16157200	2358600	(218300)	(1538500)
7	7000	24100	2723300	8.00	192800	2530500	18687700	2327400	(203100)	(1741600)
8	7000	24100	2676900	8.00	192800	2484100	21171800	2296200	(187900)	(1929500)
9	7000	24100	2630500	8.00	192800	2437700	23609500	2265100	(172600)	(2102100)
10	7000	24100	2584200	8.00	192800	2391400	26000900	2233900	(157500)	(2259600)
11	5000	17200	2256000	5.00	86000	2170000	28170900	1875000	(295000)	(2554600)
12	5000	17200	2209600	5.00	86000	2123600	30294500	1843800	(279800)	(2834400)
13	5000	17200	2163200	5.00	86000	2077200	32371700	1812600	(264600)	(3099000)
14	5000	17200	2116800	5.00	86000	2030800	34402500	1781500	(249300)	(3348300)
15	5000	17200	2070400	5.00	86000	1984400	36386900	1750300	(234100)	(3582400)
16	3500	12000	1795600	5.00	60000	1735600	38122500	1460900	(274700)	(3857100)
17	3500	12000	1749200	5.00	60000	1689200	39811700	1429700	(259500)	(4116600)
18	3500	12000	1702800	5.00	60000	1642800	41454500	1398600	(244200)	(4360800)
19	3500	12000	1656400	5.00	60000	1596400	43050900	1367400	(229000)	(4589800)
20	3500	12000	1610000	5.00	60000	1550000	44600900	1336200	(213800)	(4803600)
21	1500	5200	1212800	5.00	26000	1186800	45787700	927600	(259200)	(5062800)
22	1500	5200	1166500	5.00	26000	1140500	46928200	896400	(244100)	(5306900)
23	1500	5200	1120100	5.00	26000	1094100	48022300	865300	(228800)	(5535700)
24	1500	5200	1073700	5.00	26000	1047700	49070000	834100	(213600)	(5749300)
25	1500	5200	1027300	5.00	26000	1001300	50071300	802900	(198400)	(5947700)
26	1500	5200	9[illegible]900	5.00	26000	954900	51026200	771800	(183100)	(6130800)
27	1500	5200	934500	5.00	26000	908500	51934700	740600	(167900)	(6298700)
28	1500	5200	888200	5.00	26000	862200	52796900	709500	(152700)	(6451400)
29	1500	5200	841800	5.00	26000	815800	53612700	678300	(137500)	(6588900)
30	1500	5200	795400	5.00	26000	769400	54382100	647200	(122200)	(6711100)
TOT	127500	439000	57300100		2918000	54382100		47671000	(6711100)	
EQUIVALENT COST, DOLLARS PER BARREL OF OIL BURNED						1.45		1.27		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						2.13		1.87		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						21670900		19409800	(2261100)	
EQUIVALENT PRESENT WORTH, DOLLARS PER BARREL OF OIL BURNED						0.58		0.52		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.85		0.76		

Table A-109

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 200 MW. NEW OIL FIRED POWER PLANT, 4.0 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 7903000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	38500	3574100	8.00	308000	3266100	3266100	2698700	(567400)	(567400)
2	7000	38500	3519300	8.00	308000	3211300	6477400	2655100	(556200)	(1123600)
3	7000	38500	3464500	8.00	308000	3156500	9633900	2611500	(545000)	(1668600)
4	7000	38500	3409800	8.00	308000	3101800	12735700	2567900	(533900)	(2202500)
5	7000	38500	3355000	8.00	308000	3047000	15782700	2524300	(522700)	(2725200)
6	7000	38500	3300200	8.00	308000	2992200	18774900	2480700	(511500)	(3236700)
7	7000	38500	3245400	8.00	308000	2937400	21712300	2437100	(500300)	(3737000)
8	7000	38500	3190600	8.00	308000	2882600	24594900	2393500	(489100)	(4226100)
9	7000	38500	3135800	8.00	308000	2827800	27422700	2349900	(477900)	(4704000)
10	7000	38500	3081000	8.00	308000	2773000	30195700	2306300	(466700)	(5170700)
11	5000	27500	2682700	5.00	137500	2545200	32740900	2026300	(518900)	(5689600)
12	5000	27500	2627900	5.00	137500	2490400	35231300	1982700	(507700)	(6197300)
13	5000	27500	2573100	5.00	137500	2435600	37666900	1939100	(496500)	(6693800)
14	5000	27500	2518300	5.00	137500	2380800	40047700	1895500	(485300)	(7179100)
15	5000	27500	2463500	5.00	137500	2326000	42373700	1851900	(474100)	(7653200)
16	3500	19300	2130400	5.00	96500	2033900	44407600	1615800	(418100)	(8071300)
17	3500	19300	2075600	5.00	96500	1979100	46386700	1572200	(406900)	(8478200)
18	3500	19300	2020800	5.00	96500	1924300	48311000	1528600	(395700)	(8873900)
19	3500	19300	1966100	5.00	96500	1869600	50180600	1485000	(384600)	(9258500)
20	3500	19300	1911300	5.00	96500	1814800	51995400	1441600	(373400)	(9631900)
21	1500	8300	1433200	5.00	41500	1391700	53387100	1100800	(290900)	(9922800)
22	1500	8300	1378400	5.00	41500	1336900	54724000	1057200	(279700)	(10202500)
23	1500	8300	1323600	5.00	41500	1282100	56006100	1013600	(268500)	(10471000)
24	1500	8300	1268800	5.00	41500	1227300	57233400	970000	(257300)	(10728300)
25	1500	8300	1214000	5.00	41500	1172500	58405900	926400	(246100)	(10974400)
26	1500	8300	1159200	5.00	41500	1117700	59523600	882800	(234900)	(11209300)
27	1500	8300	1104500	5.00	41500	1063000	60586600	839200	(223800)	(11433100)
28	1500	8300	1049700	5.00	41500	1008200	61594800	795600	(212600)	(11645700)
29	1500	8300	994900	5.00	41500	953400	62548200	752000	(201400)	(11847100)
30	1500	8300	940100	5.00	41500	898600	63446800	708400	(190200)	(12037300)
TOT	127500	702000	68111800		4665000	63446800		51409500	(12037300)	
EQUIVALENT COST, DOLLARS PER BARREL OF OIL BURNED						1.69		1.37		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						2.49		2.02		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						25230000		20682100	(4547900)	
EQUIVALENT PRESENT WORTH, DOLLARS PER BARREL OF OIL BURNED						0.67		0.55		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.99		0.81		

Table A-110

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 200 MW. EXISTING OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 7426000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/ KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1										
2										
3										
4										
5										
6										
7										
8										
9	7000	24900	3329200	8.00	199200	3130000	3130000	2794100	(335900)	(335900)
10	7000	24900	3259000	8.00	199200	3059800	6189800	2732100	(327700)	(663600)
11	5000	17800	2890500	8.00	142400	2748100	8937900	2443900	(304200)	(967800)
12	5000	17800	2820300	8.00	142400	2677900	11615800	2381800	(296100)	(1263900)
13	5000	17800	2750100	8.00	142400	2607700	14223500	2319800	(287900)	(1551800)
14	5000	17800	2679900	8.00	142400	2537500	16761000	2257700	(279800)	(1831600)
15	5000	17800	2609700	8.00	142400	2467300	19228300	2195600	(271700)	(2103300)
16	3500	12400	2297200	8.00	99200	2198000	21426300	1947900	(250100)	(2353400)
17	3500	12400	2227000	8.00	99200	2127800	23554100	1885900	(241900)	(2595300)
18	3500	12400	2156800	8.00	99200	2057600	25611700	1823800	(233800)	(2829100)
19	3500	12400	2086600	5.00	62000	2024600	27636300	1761700	(262900)	(3092000)
20	3500	12400	2016400	5.00	62000	1954400	29590700	1699700	(254700)	(3346700)
21	1500	5300	1573400	5.00	26500	1546900	31137600	1349200	(197700)	(3544400)
22	1500	5300	1503200	5.00	26500	1476700	32614300	1287100	(189600)	(3734000)
23	1500	5300	1433000	5.00	26500	1406500	34020800	1225100	(181400)	(3915400)
24	1500	5300	1362800	5.00	26500	1336300	35357100	1163000	(173300)	(4088700)
25	1500	5300	1292600	5.00	26500	1266100	36623200	1100900	(165200)	(4253900)
26	1500	5300	1222400	5.00	26500	1195900	37819100	1038900	(157000)	(4410900)
27	1500	5300	1152200	5.00	26500	1125700	38944800	976800	(148900)	(4559800)
28	1500	5300	1082000	5.00	26500	1055500	40000300	914700	(140800)	(4700600)
29	1500	5300	1011800	5.00	26500	985300	40985600	852700	(132600)	(4833200)
30	1500	5300	941600	5.00	26500	915100	41900700	790600	(124500)	(4957700)
TOT	71500	253800	43697700		1797000	41900700		36943000	(4957700)	
EQUIVALENT COST, DOLLARS PER BARREL OF OIL BURNED						1.93		1.70		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						2.93		2.58		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						20155600		17862000	(2293600)	
EQUIVALENT PRESENT WORTH, DOLLARS PER BARREL OF OIL BURNED						0.93		0.82		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						1.41		1.25		

Table A-111

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 500 MW. NEW OIL FIRED POWER PLANT, 1.0 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 9888000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	23600	4242900	8.00	188900	4054100	4054100	3886100	(168000)	(168000)
2	7000	23600	4174300	8.00	188800	3985500	8039600	3820300	(165200)	(333200)
3	7000	23600	4105800	8.00	188800	3917000	11956600	3754500	(162500)	(495700)
4	7000	23600	4037200	8.00	188800	3848400	15805000	3688700	(159700)	(655400)
5	7000	23600	3968700	8.00	188800	3779900	19584900	3622900	(157000)	(812400)
6	7000	23600	3900100	8.00	188800	3711300	23296200	3557100	(154200)	(966600)
7	7000	23600	3831600	8.00	188800	3642800	26939000	3491300	(151500)	(1118100)
8	7000	23600	3763000	8.C0	188800	3574200	30513200	3425400	(148800)	(1266900)
9	7000	23600	3694400	8.00	188800	3505600	34018800	3359600	(146000)	(1412900)
10	7000	23600	3625900	8.00	188800	3437100	37455900	3293800	(143300)	(1556200)
11	5000	16800	3171300	5.00	84000	3087300	40543200	2903800	(183500)	(1739700)
12	5000	16800	3102800	5.00	84000	3018800	43562000	2838000	(180800)	(1920500)
13	5000	16800	3034200	5.00	84000	2950200	46512200	2772200	(178000)	(2098500)
14	5000	16800	2965700	5.00	84000	2881700	49393900	2706400	(175300)	(2273800)
15	5000	16800	2897100	5.00	84000	2813100	52207000	2640600	(172500)	(2446300)
16	3500	11800	2517900	5.00	59000	2458900	54665900	2312200	(146700)	(2593000)
17	3500	11800	2449300	5.00	59000	2390300	57056200	2246300	(144000)	(2737000)
18	3500	11800	2380700	5.00	59000	2321700	59377900	2180500	(141200)	(2878200)
19	3500	11800	2312200	5.00	59000	2253200	61631100	2114700	(138500)	(3016700)
20	3500	11800	2243600	5.00	59000	2184600	63815700	2048900	(135700)	(3152400)
21	1500	5000	1705000	5.00	25000	1680000	65495700	1583000	(97000)	(3249400)
22	1500	5000	1636400	5.00	25000	1611400	67107100	1517200	(94200)	(3343600)
23	1500	5000	1567900	5.00	25000	1542900	68650000	1451400	(91500)	(3435100)
24	1500	5000	1499300	5.00	25000	1474300	70124300	1385600	(88700)	(3523800)
25	1500	5000	1430700	5.00	25000	1405700	71530000	1319800	(85900)	(3609700)
26	1500	5000	1362200	5.00	25000	1337200	72867200	1253900	(83300)	(3693000)
27	1500	5000	1293600	5.00	25000	1268600	74135800	1188100	(80500)	(3773500)
28	1500	5000	1225100	5.C0	25000	1200100	75335900	1122300	(77800)	(3851300)
29	1500	5000	1156500	5.00	25000	1131500	76467400	1056500	(75000)	(3926300)
30	1500	5000	1088000	5.00	25000	1063000	77530400	990700	(72300)	(3998600)
TOT	127500	429000	80383400		2853000	77530400		73531800	(3998600)	
EQUIVALENT COST, DOLLARS PER BARREL OF OIL BURNED						0.85		0.80		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						1.22		1.15		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						31092000		29653900	(1438100)	
EQUIVALENT PRESENT WORTH, DOLLARS PER BARREL OF OIL BURNED						0.34		0.32		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.49		0.47		

Table A-112

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 500 MW. NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 12439000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UN S T	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	58900	5453800	8.00	471200	4982600	4982600	4454500	(528100)	(528100)
2	7000	58900	5367600	8.00	471200	4896400	9879000	4380500	(515900)	(1044000)
3	7000	58900	5281300	8.00	471200	4810100	14689100	4306400	(503700)	(1547700)
4	7000	58900	5195100	8.00	471200	4723900	19413000	4232400	(491500)	(2039200)
5	7000	58900	5108900	8.00	471200	4637700	24050700	4158300	(479600)	(2518600)
6	7000	58900	5022600	8.00	471200	4551400	28602100	4084300	(467100)	(2985700)
7	7000	58900	4936400	8.00	471200	4465200	33067300	4010200	(455000)	(3440700)
8	7000	58900	4850200	8.00	471200	4379000	37446300	3936200	(442800)	(3883500)
9	7000	58900	4763900	8.00	471200	4292700	41739000	3862100	(430600)	(4314100)
10	7000	58900	4677700	8.00	471200	4206500	45945500	3788100	(418400)	(4732500)
11	5000	42100	4066300	5.00	210500	3855800	49801300	3325700	(530100)	(5262600)
12	5000	42100	3980100	5.00	210500	3769600	53570900	3251600	(518000)	(5780600)
13	5000	42100	3893900	5.00	210500	3683400	57254300	3177600	(505800)	(6286400)
14	5000	42100	3807600	5.00	210500	3597100	60851400	3103500	(493600)	(6780000)
15	5000	42100	3721400	5.00	210500	3510900	64362300	3029500	(481400)	(7261400)
16	3500	29400	3216000	5.00	147000	3069000	67431300	2642700	(426300)	(7687700)
17	3500	29400	3129700	5.00	147000	2982700	70414000	2568700	(414000)	(8101700)
18	3500	29400	3043500	5.00	147000	2896500	73310500	2494600	(401900)	(8503600)
19	3500	29400	2957200	5.00	147000	2810200	76120700	2420600	(389600)	(8893200)
20	3500	29400	2871000	5.00	147000	2724000	78844700	2346500	(377500)	(9270700)
21	1500	12600	2158900	5.00	63000	2095900	80940600	1798300	(297600)	(9568300)
22	1500	12600	2072600	5.00	63000	2009600	82950200	1724200	(285400)	(9853700)
23	1500	12600	1986400	5.00	63000	1923400	84873600	1650200	(273200)	(10126900)
24	1500	12600	1900200	5.00	63000	1837200	86710800	1576100	(261100)	(10388000)
25	1500	12600	1813900	5.00	63000	1750900	88461700	1502100	(248800)	(10636800)
26	1500	12600	1727700	5.00	63000	1664700	90126400	1428000	(236700)	(10873500)
27	1500	12600	1641500	5.00	63000	1578500	91704900	1354000	(224500)	(11098000)
28	1500	12600	1555200	5.00	63000	1492200	93197100	1279900	(212300)	(11310300)
29	1500	12600	1469000	5.00	63000	1406000	94603100	1205900	(200100)	(11510400)
30	1500	12600	1382700	5.00	63000	1319700	95922800	1131800	(187900)	(11698300)
TOT	127500	1072500	103052300		7129500	95922800		84224500	(11698300)	
EQUIVALENT COST, DOLLARS PER BARREL OF OIL BURNED						1.05		0.92		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						1.50		1.32		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						38313300		34007700	(4305600)	
EQUIVALENT PRESENT WORTH, DOLLARS PER BARREL OF OIL BURNED						0.42		0.37		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.60		0.53		

Table A-113

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 500 MW. NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 12439000

Includes comparison with projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	58900	5453800	8.00	471200	4982600	4982600	5015800	33200	33200
2	7000	58900	5367600	8.00	471200	4896400	9879000	4955600	59200	92400
3	7000	58900	5281300	8.00	471200	4810100	14689100	4895400	85300	177700
4	7000	58900	5195100	8.00	471200	4723900	19413000	4835200	111300	289000
5	7000	58900	5108900	8.00	471200	4637700	24050700	4775000	137300	426300
6	7000	58900	5022600	8.00	471200	4551400	28602100	4714800	163400	589700
7	7000	58900	4936400	8.00	471200	4465200	33067300	4654600	189400	779100
8	7000	58900	4850200	8.00	471200	4379000	37446300	4594400	215400	994500
9	7000	58900	4763900	8.00	471200	4292700	41739000	4534200	241500	1236000
10	7000	58900	4677700	8.00	471200	4206500	45945500	4474000	267500	1503500
11	5000	42100	4066300	5.00	210500	3855800	49801300	3712000	(143800)	1359700
12	5000	42100	3980100	5.00	210500	3769600	53570900	3651800	(117800)	1241900
13	5000	42100	3893900	5.00	210500	3683400	57254300	3591600	(91800)	1150100
14	5000	42100	3807600	5.00	210500	3597100	60851400	3531400	(65700)	1084400
15	5000	42100	3721400	5.00	210500	3510900	64362300	3471200	(39700)	1044700
16	3500	29400	3216000	5.00	147000	3069000	67431300	2865100	(203900)	840800
17	3500	29400	3129700	5.00	147000	2982700	70414000	2804900	(177800)	663000
18	3500	29400	3043500	5.00	147000	2896500	73310500	2744700	(151800)	511200
19	3500	29400	2957200	5.00	147000	2810200	76120700	2684600	(125600)	385600
20	3500	29400	2871000	5.00	147000	2724000	78844700	2624400	(99600)	286000
21	1500	12600	2158900	5.00	63000	2095900	80940600	1783400	(312500)	(26500)
22	1500	12600	2072600	5.00	63000	2009600	82950200	1723200	(286400)	(312900)
23	1500	12600	1986400	5.00	63000	1923400	84873600	1663000	(260400)	(573300)
24	1500	12600	1900200	5.00	63000	1837200	86710800	1602800	(234400)	(807700)
25	1500	12600	1813900	5.00	63000	1750900	88461700	1542600	(208300)	(1016000)
26	1500	12600	1727700	5.00	63000	1664700	90126400	1482400	(182300)	(1198300)
27	1500	12600	1641500	5.00	63000	1578500	91704900	1422200	(156300)	(1354600)
28	1500	12600	1555200	5.00	63000	1492200	93197100	1362000	(130200)	(1484800)
29	1500	12600	1469000	5.00	63000	1406000	94603100	1301800	(104200)	(1589000)
30	1500	12600	1382700	5.00	63000	1319700	95922800	1241600	(78100)	(1667100)
TOT	127500	1072500	103052300		7129500	95922800		94255700	(1667100)	
EQUIVALENT COST, DOLLARS PER BARREL OF OIL BURNED						1.05		1.03		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						1.50		1.48		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						38313300		38632900	319600	
EQUIVALENT PRESENT WORTH, DOLLARS PER BARREL OF OIL BURNED						0.42		0.42		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.60		0.61		

Table A-114

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 500 MW. NEW OIL FIRED POWER PLANT, 4.0 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 14568000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	94200	6489000	8.00	753600	5735400	5735400	4964100	(771300)	(771300)
2	7000	94200	6388000	8.00	753600	5634400	11369800	4883000	(751400)	(1522700)
3	7000	94200	6287000	8.00	753600	5533400	16903200	4801900	(731500)	(2254200)
4	7000	94200	6186000	8.00	753600	5432400	22335600	4720800	(711600)	(2965800)
5	7000	94200	6085000	8.00	753600	5331400	27667000	4639700	(691700)	(3657500)
6	7000	94200	5984000	8.00	753600	5230400	32897400	4558600	(671800)	(4329300)
7	7000	94200	5883000	8.00	753600	5129400	38026800	4477500	(651900)	(4981200)
8	7000	94200	5782000	8.00	753600	5028400	43055200	4396400	(632000)	(5613200)
9	7000	94200	5681000	8.00	753600	4927400	47982600	4315300	(612100)	(6225300)
10	7000	94200	5580000	8.00	753600	4826400	52809000	4234200	(592200)	(6817500)
11	5000	67300	4831400	5.00	336500	4494900	57303900	3703700	(791200)	(7608700)
12	5000	67300	4730400	5.00	336500	4393900	61697800	3622600	(771300)	(8380000)
13	5000	67300	4629400	5.00	336500	4292900	65990700	3541500	(751400)	(9131400)
14	5000	67300	4528400	5.00	336500	4191900	70182600	3460400	(731500)	(9862900)
15	5000	67300	4427400	5.00	336500	4090900	74273500	3379300	(711600)	(10574500)
16	3500	47100	3811700	5.00	235500	3576200	77849700	2937400	(638800)	(11213300)
17	3500	47100	3710700	5.00	235500	3475200	81324900	2856300	(618900)	(11832200)
18	3500	47100	3609700	5.00	235500	3374200	84699100	2775200	(599000)	(12431200)
19	3500	47100	3508700	5.00	235500	3273200	87972300	2694100	(579100)	(13010300)
20	3500	47100	3407700	5.00	235500	3172200	91144500	2613000	(559200)	(13569500)
21	1500	20200	2543100	5.00	101000	2442100	93586600	1988500	(453600)	(14023100)
22	1500	20200	2442100	5.00	101000	2341100	95927700	1907400	(433700)	(14456800)
23	1500	20200	2341100	5.00	101000	2240100	98167800	1826300	(413800)	(14870600)
24	1500	20200	2240100	5.00	101000	2139100	100306900	1745200	(393900)	(15264500)
25	1500	20200	2139100	5.00	101000	2038100	102345000	1664100	(374000)	(15638500)
26	1500	20200	2038100	5.00	101000	1937100	104282100	1583000	(354100)	(15992600)
27	1500	20200	1937100	5.00	101000	1836100	106118200	1501900	(334200)	(16326800)
28	1500	20200	1836100	5.00	101000	1735100	107853300	1420800	(314300)	(16641100)
29	1500	20200	1735100	5.00	101000	1634100	109487400	1339700	(294400)	(16935500)
30	1500	20200	1634100	5.00	101000	1533100	111020500	1258600	(274500)	(17210000)
TOT	127500	1716000	122426500		11406000	111020500		93810500	(17210000)	
EQUIVALENT COST, DOLLARS PER BARREL OF OIL BURNED						1.21		1.02		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						1.74		1.47		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						44197900		37916800	(6281100)	
EQUIVALENT PRESENT WORTH, DOLLARS PER BARREL OF OIL BURNED						0.48		0.41		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.69		0.59		

Table A-115

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 500 MW. EXISTING OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 13920000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1										
2										
3										
4	7000	60200	5997100	8.00	481600	5515500	5515500	5032800	(482700)	(482700)
5	7000	60200	5889800	8.00	481600	5408200	10923700	4938200	(470000)	(952700)
6	7000	60200	5782600	8.00	481600	5301000	16224700	4843600	(457400)	(1410100)
7	7000	60200	5675300	8.00	481600	5193700	21418400	4749000	(444700)	(1854800)
8	7000	60200	5568100	8.00	481600	5086500	26504900	4654400	(432100)	(2286900)
9	7000	60200	5460800	8.00	481600	4979200	31484100	4559800	(419400)	(2706300)
10	7000	60200	5353600	8.00	481600	4872000	36356100	4465100	(406900)	(3113200)
11	5000	43000	4693300	8.00	344000	4349300	40705400	3953400	(395900)	(3509100)
12	5000	43000	4586100	8.00	344000	4242100	44947500	3858800	(383300)	(3892400)
13	5000	43000	4478900	8.00	344000	4134900	49082400	3764200	(370700)	(4263100)
14	5000	43000	4371600	5.00	215000	4156600	53239000	3669600	(487000)	(4750100)
15	5000	43000	4264400	5.00	215000	4049400	57288600	3574900	(474500)	(5224600)
16	3500	30100	3714400	5.00	150500	3563900	60852300	3143500	(420400)	(5645000)
17	3500	30100	3607200	5.00	150500	3456700	64309000	3048900	(407800)	(6052800)
18	3500	30100	3499900	5.00	150500	3349400	67658400	2954300	(395100)	(6447900)
19	3500	30100	3392700	5.00	150500	3242200	70900600	2859700	(382500)	(6830400)
20	3500	30100	3285400	5.00	150500	3134900	74035500	2765000	(369900)	(7200300)
21	1500	12900	2514800	5.00	64500	2450300	76485800	2157000	(293300)	(7493600)
22	1500	12900	2407600	5.00	64500	2343100	78828900	2062400	(280700)	(7774300)
23	1500	12900	2300300	5.00	64500	2235800	81064700	1967800	(268000)	(8042300)
24	1500	12900	2193100	5.00	64500	2128600	83193300	1873200	(255400)	(8297700)
25	1500	12900	2085800	5.00	64500	2021300	85214600	1778500	(242800)	(8540500)
26	1500	12900	1978600	5.00	64500	1914100	87128700	1683900	(230200)	(8770700)
27	1500	12900	1871300	5.00	64500	1806800	88935500	1589300	(217500)	(8988200)
28	1500	12900	1764100	5.00	64500	1699600	90635100	1494700	(204900)	(9193100)
29	1500	12900	1656800	5.00	64500	1592300	92227400	1400100	(192200)	(9385300)
30	1500	12900	1549600	5.00	64500	1485100	93712500	1305400	(179700)	(9565000)
TOT	106500	915900	99943200		6230700	93712500		84147500	(9565000)	
EQUIVALENT COST, DOLLARS PER BARREL OF OIL BURNED						1.20		1.07		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						1.76		1.58		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						40215400		36435400	(3780000)	
EQUIVALENT PRESENT WORTH, DOLLARS PER BARREL OF OIL BURNED						0.51		0.47		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.76		0.68		

Table A-116

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 1000 MW. NEW OIL FIRED POWER PLANT, 1.0 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 14957000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	45500	6373300	8.00	364000	6009300	6009300	5979600	(29700)	(29700)
2	7000	45500	6269500	8.00	364000	5905500	11914800	5877300	(28200)	(57900)
3	7000	45500	6165800	8.00	364000	5801800	17716600	5774900	(26900)	(84800)
4	7000	45500	6062100	8.00	364000	5698100	23414700	5672500	(25600)	(110400)
5	7000	45500	5958400	8.00	364000	5594400	29009100	5570100	(24300)	(134700)
6	7000	45500	5854700	8.00	364000	5490700	34499800	5467700	(23000)	(157700)
7	7000	45500	5751000	8.00	364000	5387000	39886800	5365400	(21600)	(179300)
8	7000	45500	5647300	8.00	364000	5283300	45170100	5263000	(20300)	(199600)
9	7000	45500	5543600	8.00	364000	5179600	50349700	5160600	(19000)	(218600)
10	7000	45500	5439900	8.00	364000	5075900	55425600	5058200	(17700)	(236300)
11	5000	32500	4735600	5.00	162500	4573100	59998700	4448600	(124500)	(360800)
12	5000	32500	4631900	5.00	162500	4469400	64468100	4346200	(123200)	(484000)
13	5000	32500	4528200	5.00	162500	4365700	68833800	4243800	(121900)	(605900)
14	5000	32500	4424400	5.00	162500	4261900	73095700	4141400	(120500)	(726400)
15	5000	32500	4320700	5.00	162500	4158200	77253900	4039000	(119200)	(845600)
16	3500	22800	3740300	5.00	114000	3626300	80880200	3530500	(95800)	(941400)
17	3500	22800	3636600	5.00	114000	3522600	84402800	3428100	(94500)	(1035900)
18	3500	22800	3532900	5.00	114000	3418900	87821700	3325700	(93200)	(1129100)
19	3500	22800	3429200	5.00	114000	3315200	91136900	3223300	(91900)	(1221000)
20	3500	22800	3325500	5.00	114000	3211500	94348400	3121000	(90500)	(1311500)
21	1500	9800	2516500	5.00	49000	2467500	96815900	2409700	(57800)	(1369300)
22	1500	9800	2412800	5.00	49000	2363800	99179700	2307300	(56500)	(1425800)
23	1500	9800	2309100	5.00	49000	2260100	101439800	2204900	(55200)	(1481000)
24	1500	9800	2205400	5.00	49000	2156400	103596200	2102500	(53900)	(1534900)
25	1500	9800	2101600	5.00	49000	2052600	105648800	2000200	(52400)	(1587300)
26	1500	9800	1997900	5.00	49000	1948900	107597700	1897800	(51100)	(1638400)
27	1500	9800	1894200	5.00	49000	1845200	109442900	1795400	(49800)	(1688200)
28	1500	9800	1790500	5.00	49000	1741500	111184400	1693000	(48500)	(1736700)
29	1500	9800	1686800	5.00	49000	1637800	112822200	1590700	(47100)	(1783800)
30	1500	9800	1583100	5.00	49000	1536100	114356300	1490300	(45800)	(1829600)
TOT	127500	829500	119868800		5512500	114356300		112526700	(1829600)	
EQUIVALENT COST, DOLLARS PER BARREL OF OIL BURNED						0.65		0.63		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						0.90		0.88		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						45980700		45517600	(463100)	
EQUIVALENT PRESENT WORTH, DOLLARS PER BARREL OF OIL BURNED						0.26		0.26		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.36		0.36		

Table A-117

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 1000 MW. NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 18888000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	113900	8282100	8.00	911200	7370900	7370900	6890400	(480500)	(480500)
2	7000	113900	8151100	8.00	911200	7239900	14610800	6775100	(464800)	(945300)
3	7000	113900	8020200	8.00	911200	7109000	21719800	6659800	(449200)	(1394500)
4	7000	113900	7889200	8.00	911200	6978000	28697800	6544500	(433500)	(1828000)
5	7000	113900	7758300	8.00	911200	6847100	35544900	6429300	(417800)	(2245800)
6	7000	113900	7627300	8.00	911200	6716100	42261000	6314000	(402100)	(2647900)
7	7000	113900	7496400	8.00	911200	6585200	48846200	6198700	(386500)	(3034400)
8	7000	113900	7365400	8.00	911200	6454200	55300400	6083400	(370800)	(3405200)
9	7000	113900	7234400	8.00	911200	6323200	61623600	5968100	(355100)	(3760300)
10	7000	113900	7103500	8.00	911200	6192300	67815900	5852800	(339500)	(4099800)
11	5000	81300	6139400	5.00	406500	5732900	73548800	5120700	(612200)	(4712000)
12	5000	81300	6008500	5.00	406500	5602000	79150800	5005400	(596600)	(5308600)
13	5000	81300	5877500	5.00	406500	5471000	84621800	4890100	(580900)	(5889500)
14	5000	81300	5746600	5.00	406500	5340100	89961900	4774800	(565300)	(6454800)
15	5000	81300	5615600	5.00	406500	5209100	95171000	4659500	(549600)	(7004400)
16	3500	56900	4827800	5.00	284500	4543300	99714300	4052800	(490500)	(7494900)
17	3500	56900	4696800	5.00	284500	4412300	104126600	3937500	(474800)	(7969700)
18	3500	56900	4565800	5.00	284500	4281300	108407900	3822200	(459100)	(8428800)
19	3500	56900	4434900	5.00	284500	4150400	112558300	3706900	(443500)	(8872300)
20	3500	56900	4303900	5.00	284500	4019400	116577700	3591600	(427800)	(9300100)
21	1500	24400	3213400	5.00	122000	3091400	119669100	2745400	(346000)	(9646100)
22	1500	24400	3082400	5.00	122000	2960400	122629500	2630100	(330300)	(9976400)
23	1500	24400	2951500	5.00	122000	2829500	125459000	2514900	(314600)	(10291000)
24	1500	24400	2820500	5.00	122000	2698500	128157500	2399600	(298900)	(10589900)
25	1500	24400	2689500	5.00	122000	2567500	130725000	2284300	(283200)	(10873100)
26	1500	24400	2558600	5.00	122000	2436600	133161600	2169000	(267600)	(11140700)
27	1500	24400	2427600	5.00	122000	2305600	135467200	2053700	(251900)	(11392600)
28	1500	24400	2296700	5.00	122000	2174700	137641900	1938400	(236300)	(11628900)
29	1500	24400	2165700	5.00	122000	2043700	139685600	1823100	(220600)	(11849500)
30	1500	24400	2034800	5.00	122000	1912800	141598400	1707800	(205000)	(12054500)
TOT	127500	2074000	155385400		13787000	141598400		129543900	(12054500)	
EQUIVALENT COST, DOLLARS PER BARREL OF OIL BURNED						0.80		0.73		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						1.11		1.02		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						56611200		52482100	(4129100)	
EQUIVALENT PRESENT WORTH, DOLLARS PER BARREL OF OIL BURNED						0.32		0.30		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.44		0.41		

Table A-118

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 1000 MW. NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 18888000

Includes comparison with projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	113900	8282100	8.00	911200	7370900	7370900	8261100	890200	890200
2	7000	113900	8151100	8.00	911200	7239900	14610800	8166900	927000	1817200
3	7000	113900	8020200	8.00	911200	7109000	21719800	8072700	963700	2780900
4	7000	113900	7889200	8.00	911200	6978000	28697800	7978500	1000500	3781400
5	7000	113900	7758300	8.00	911200	6847100	35544900	7884300	1037200	4818600
6	7000	113900	7627300	8.00	911200	6716100	42261000	7790200	1074100	5892700
7	7000	113900	7496400	8.00	911200	6585200	48846200	7696000	1110800	7003500
8	7000	113900	7365400	8.00	911200	6454200	55300400	7601800	1147600	8151100
9	7000	113900	7234400	6.00	911200	6323200	61623600	7507600	1184400	9335500
10	7000	113900	7103500	8.00	911200	6192300	67815900	7413400	1221100	10556600
11	5000	81300	6139400	5.00	406500	5732900	73548800	6082300	349400	10906000
12	5000	81300	6008500	5.00	406500	5602000	79150800	5988200	386200	11292200
13	5000	81300	5877500	5.00	406500	5471000	84621800	5894000	423000	11715200
14	5000	81300	5746600	5.00	406500	5340100	89961900	5799800	459700	12174900
15	5000	81300	5615600	5.00	406500	5209100	95171000	5705600	496500	12671400
16	3500	56900	4827800	5.00	284500	4543300	99714300	4656200	112900	12784300
17	3500	56900	4696800	5.00	284500	4412300	104126600	4562000	149700	12934000
18	3500	56900	4565800	5.00	284500	4281300	108407900	4467900	186600	13120600
19	3500	56900	4434900	5.00	284500	4150400	112558300	4373700	223300	13343900
20	3500	56900	4303900	5.00	284500	4019400	116577700	4279500	260100	13604000
21	1500	24400	3213400	5.00	122000	3091400	119669100	2840700	(250700)	13353300
22	1500	24400	3082400	5.00	122000	2960400	122629500	2746500	(213900)	13139400
23	1500	24400	2951500	5.00	122000	2829500	125459000	2652400	(177100)	12962300
24	1500	24400	2820500	5.00	122000	2698500	128157500	2558200	(140300)	12822000
25	1500	24400	2689500	5.00	122000	2567500	130725000	2464000	(103500)	12718500
26	1500	24400	2558600	5.00	122000	2436600	133161600	2369800	(66800)	12651700
27	1500	24400	2427600	5.00	122000	2305600	135467200	2275600	(30000)	12621700
28	1500	24400	2296700	5.00	122000	2174700	137641900	2181400	6700	12628400
29	1500	24400	2165700	5.00	122000	2043700	139685600	2087300	43600	12672000
30	1500	24400	2034800	5.00	122000	1912800	141598400	1993100	80300	12752300
TOT	127500	2074000	155385400		13787000	141598400		154350700	12752300	
EQUIVALENT COST, DOLLARS PER BARREL OF OIL BURNED						0.80		0.87		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						1.11		1.21		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						56611200		63589800	6978600	
EQUIVALENT PRESENT WORTH, DOLLARS PER BARREL OF OIL BURNED						0.32		0.36		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.44		0.50		

Table A-119

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 1000 MW. NEW OIL FIRED POWER PLANT, 4.0 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 22046000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	182200	9859800	8.00	1457600	8402200	8402200	7717900	(684300)	(684300)
2	7000	182200	9706900	8.00	1457600	8249300	16651500	7591700	(657600)	(1341900)
3	7000	182200	9554000	8.00	1457600	8096400	24747900	7465500	(630900)	(1972800)
4	7000	182200	9401200	8.00	1457600	7943600	32691500	7339300	(604300)	(2577100)
5	7000	182200	9248300	8.00	1457600	7790700	40482200	7213100	(577600)	(3154700)
6	7000	182200	9095500	8.00	1457600	7637900	48120100	7086900	(551000)	(3705700)
7	7000	182200	8942600	8.00	1457600	7485000	55605100	6960800	(524200)	(4229900)
8	7000	182200	8789800	8.00	1457600	7332200	62937300	6834600	(497600)	(4727500)
9	7000	182200	8636900	8.00	1457600	7179300	70116600	6708400	(470900)	(5198400)
10	7000	182200	8484000	8.00	1457600	7026400	77143000	6582200	(444200)	(5642600)
11	5000	130100	7296600	5.00	650500	6646100	83789100	5732700	(913400)	(6556000)
12	5000	130100	7143700	5.00	650500	6493200	90282300	5606500	(886700)	(7442700)
13	5000	130100	6990900	5.00	650500	6340400	96622700	5480300	(860100)	(8302800)
14	5000	130100	6838000	5.00	650500	6187500	102810200	5354100	(833400)	(9136200)
15	5000	130100	6685100	5.00	650500	6034600	108844800	5227900	(806700)	(9942900)
16	3500	91100	5720400	5.00	455500	5264900	114109700	4527300	(737600)	(10680500)
17	3500	91100	5567500	5.00	455500	5112000	119221700	4401100	(710900)	(11391400)
18	3500	91100	5414700	5.00	455500	4959200	124180900	4274900	(684300)	(12075700)
19	3500	91100	5261800	5.00	455500	4806300	128987200	4148700	(657600)	(12733300)
20	3500	91100	5108900	5.00	455500	4653400	133640600	4022500	(630900)	(13364200)
21	1500	39000	3778700	5.00	195000	3583700	137224300	3046900	(536800)	(13901000)
22	1500	39000	3625800	5.00	195000	3430800	140655100	2920800	(510000)	(14411000)
23	1500	39000	3473000	5.00	195000	3278000	143933100	2794600	(483400)	(14894400)
24	1500	39000	3320100	5.00	195000	3125100	147058200	2668400	(456700)	(15351100)
25	1500	39000	3167200	5.00	195000	2972200	150030400	2542200	(430000)	(15781100)
26	1500	39000	3014400	5.00	195000	2819400	152849800	2416000	(403400)	(16184500)
27	1500	39000	2861500	5.00	195000	2666500	155516300	2289800	(376700)	(16561200)
28	1500	39000	2708700	5.00	195000	2513700	158030000	2163600	(350100)	(16911300)
29	1500	39000	2555800	5.00	195000	2360800	160390800	2037400	(323400)	(17234700)
30	1500	39000	2403000	5.00	195000	2208000	162598800	1911200	(296800)	(17531500)
TOT	127500	3318000	184654800		22056000	162598800		145067300	(17531500)	
EQUIVALENT COST, DOLLARS PER BARREL OF OIL BURNED						0.92		0.82		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						1.28		1.14		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						64717200		58833700	(5883500)	
EQUIVALENT PRESENT WORTH, DOLLARS PER BARREL OF OIL BURNED						0.37		0.33		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.51		0.46		

Table A-120

MAGNESIA SCHEME A, REGULATED POWER CO. ECONOMICS, 1000 MW. EXISTING OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 20740000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1										
2										
3										
4	7000	117800	8979700	8.00	942400	8037300	8037300	7604800	(432500)	(432500)
5	7000	117800	8820000	8.00	942400	7877600	15914900	7463300	(414300)	(846800)
6	7000	117800	8660200	8.00	942400	7717800	23632700	7321900	(395900)	(1242700)
7	7000	117800	8500400	8.00	942400	7558000	31190700	7180400	(377600)	(1620300)
8	7000	117800	8340700	8.00	942400	7398300	38589000	7039000	(359300)	(1979600)
9	7000	117800	8180900	8.00	942400	7238500	45827500	6897500	(341000)	(2320600)
10	7000	117800	8021100	8.00	942400	7078700	52906200	6756000	(322700)	(2643300)
11	5000	84100	6987100	8.00	672800	6314300	59220500	5942200	(372100)	(3015400)
12	5000	84100	6827300	8.00	672800	6154500	65375000	5800700	(353800)	(3369200)
13	5000	84100	6667500	8.00	672800	5994700	71369700	5659200	(335500)	(3704700)
14	5000	84100	6507800	5.00	420500	6087300	77457000	5517800	(569500)	(4274200)
15	5000	84100	6348000	5.00	420500	5927500	83384500	5376300	(551200)	(4825400)
16	3500	58900	5498400	5.00	294500	5203900	88588400	4699300	(504600)	(5330000)
17	3500	58900	5338700	5.00	294500	5044200	93632600	4557800	(486400)	(5816400)
18	3500	58900	5178900	5.00	294500	4884400	98517000	4416300	(468100)	(6284500)
19	3500	58900	5019100	5.00	294500	4724600	103241600	4274900	(449700)	(6734200)
20	3500	58900	4859400	5.00	294500	4564900	107806500	4133400	(431500)	(7165700)
21	1500	25200	3688700	5.00	126000	3562700	111369200	3195900	(366800)	(7532500)
22	1500	25200	3529000	5.00	126000	3403000	114772200	3054400	(348600)	(7881100)
23	1500	25200	3369200	5.00	126000	3243200	118015400	2912900	(330300)	(8211400)
24	1500	25200	3209400	5.00	126000	3083400	121098800	2771500	(311900)	(8523300)
25	1500	25200	3049700	5.00	126000	2923700	124022500	2630000	(293700)	(8817000)
26	1500	25200	2889900	5.00	126000	2763900	126786400	2488600	(275300)	(9092300)
27	1500	25200	2730100	5.00	126000	2604100	129390500	2347100	(257000)	(9349300)
28	1500	25200	2570400	5.00	126000	2444400	131834900	2205600	(238800)	(9588100)
29	1500	25200	2410600	5.00	126000	2284600	134119500	2064200	(220400)	(9808500)
30	1500	25200	2250800	5.00	126000	2124800	136244300	1922700	(202100)	(10010600)
TOT	106500	1791600	148433000		12188700	136244300		126233700	(10010600)	
EQUIVALENT COST, DOLLARS PER BARREL OF OIL BURNED						0.89		0.82		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						1.28		1.19		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						58523000		54890100	(3632900)	
EQUIVALENT PRESENT WORTH, DOLLARS PER BARREL OF OIL BURNED						0.38		0.36		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.55		0.52		

Table A-121

MAGNESIA SCHEME B, REGULATED POWER CO. ECONOMICS, 200 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 11990000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	45200	5187000	8.00	361600	4825400	4825400	3825400	(1000000)	(1000000)
2	7000	45200	5103900	8.00	361600	4742300	9567700	3761700	(980600)	(1980600)
3	7000	45200	5020700	8.00	361600	4659100	14226800	3698000	(961100)	(2941700)
4	7000	45200	4937600	8.00	361600	4576000	18802800	3634200	(941800)	(3883500)
5	7000	45200	4854500	8.00	361600	4492900	23295700	3570500	(922400)	(4805900)
6	7000	45200	4771300	8.00	361600	4409700	27705400	3506800	(902900)	(5708800)
7	7000	45200	4688200	8.00	361600	4326600	32032000	3443000	(883600)	(6592400)
8	7000	45200	4605100	8.00	361600	4243500	36275500	3379300	(864200)	(7456600)
9	7000	45200	4521900	8.00	361600	4160300	40435800	3315600	(844700)	(8301300)
10	7000	45200	4438800	8.00	361600	4077200	44513000	3251900	(825300)	(9126600)
11	5000	32300	3884900	5.00	161500	3723400	48236400	2868100	(855300)	(9981900)
12	5000	32300	3801800	5.00	161500	3640300	51876700	2804400	(835900)	(10817800)
13	5000	32300	3718700	5.00	161500	3557200	55433900	2740700	(816500)	(11634300)
14	5000	32300	3635500	5.00	161500	3474000	58907900	2676900	(797100)	(12431400)
15	5000	32300	3552400	5.00	161500	3390900	62298800	2613200	(777700)	(13209100)
16	3500	22600	3088300	5.00	113000	2975300	65274100	2288900	(686400)	(13895500)
17	3500	22600	3005100	5.00	113000	2892100	68166200	2225100	(667000)	(14562500)
18	3500	22600	2922000	5.00	113000	2809000	70975200	2161400	(647600)	(15210100)
19	3500	22600	2838800	5.00	113000	2725800	73701000	2097700	(628100)	(15838200)
20	3500	22600	2755700	5.00	113000	2642700	76343700	2033900	(608800)	(16447000)
21	1500	9700	2092600	5.00	48500	2044100	78387800	1567700	(476400)	(16923400)
22	1500	9700	2009400	5.00	48500	1960900	80348700	1504000	(456900)	(17380300)
23	1500	9700	1926300	5.00	48500	1877800	82226500	1440200	(437600)	(17817900)
24	1500	9700	1843200	5.00	48500	1794700	84021200	1376500	(418200)	(18236100)
25	1500	9700	1760000	5.00	48500	1711500	85732700	1312800	(398700)	(18634800)
26	1500	9700	1676900	5.00	48500	1628400	87361100	1249100	(379300)	(19014100)
27	1500	9700	1593700	5.00	48500	1545200	88906300	1185300	(359900)	(19374000)
28	1500	9700	1510600	5.00	48500	1462100	90368400	1121600	(340500)	(19714500)
29	1500	9700	1427500	5.00	48500	1379000	91747400	1057900	(321100)	(20035600)
30	1500	9700	1344300	5.00	48500	1295800	93043200	994100	(301700)	(20337300)
TOT	127500	823500	98516700		5473500	93043200		72705900	(20337300)	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						9.52		7.44		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						3.65		2.85		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						37116300		29257300	(7859000)	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						3.80		2.99		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						1.46		1.15		

Table A-122

MAGNESIA SCHEME B, REGULATED POWER CO. ECONOMICS, 500 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 22237000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	110400	9474700	8.00	883200	8591500	8591500	7209600	(1381900)	(1381900)
2	7000	110400	9320500	8.00	883200	8437300	17028800	7087400	(1349900)	(2731800)
3	7000	110400	9166400	8.00	883200	8283200	25312000	6965200	(1318000)	(4049800)
4	7000	110400	9012200	8.00	883200	8129000	33441000	6843000	(1286000)	(5335800)
5	7000	110400	8858000	8.00	883200	7974800	41415800	6720900	(1253900)	(6589700)
6	7000	110400	8703800	8.00	883200	7820600	49236400	6598700	(1221900)	(7811600)
7	7000	110400	8549700	8.00	883200	7666500	56902900	6476500	(1190000)	(9001600)
8	7000	110400	8395500	8.00	883200	7512300	64415200	6354300	(1158000)	(10159600)
9	7000	110400	8241300	8.00	883200	7358100	71773300	6232100	(1126000)	(11285600)
10	7000	110400	8087200	8.00	883200	7204000	78977300	6110000	(1094000)	(12379600)
11	5000	78900	7053700	5.00	394500	6659200	85636500	5381100	(1278100)	(13657700)
12	5000	78900	6899500	5.00	394500	6505000	92141500	5258900	(1246100)	(14903800)
13	5000	78900	6745400	5.00	394500	6350900	98492400	5136700	(1214200)	(16118000)
14	5000	78900	6591200	5.00	394500	6196700	104689100	5014500	(1182200)	(17300200)
15	5000	78900	6437000	5.00	394500	6042500	110731600	4892600	(1150100)	(18450300)
16	3500	55200	5581500	5.00	276000	5305500	116037100	4280700	(1024800)	(19475100)
17	3500	55200	5427300	5.00	276000	5151300	121188400	4158500	(992800)	(20467900)
18	3500	55200	5273100	5.00	276000	4997100	126185500	4036300	(960800)	(21428700)
19	3500	55200	5118900	5.00	276000	4842900	131028400	3914200	(928700)	(22357400)
20	3500	55200	4964800	5.00	276000	4688800	135717200	3792000	(896800)	(23254200)
21	1500	23700	3763700	5.00	118500	3645200	139362400	2926100	(719100)	(23973300)
22	1500	23700	3609500	5.00	118500	3491000	142853400	2803900	(687100)	(24660400)
23	1500	23700	3455400	5.00	118500	3336900	146190300	2681700	(655200)	(25315600)
24	1500	23700	3301200	5.00	118500	3182700	149373000	2559600	(623100)	(25938700)
25	1500	23700	3147000	5.00	118500	3028500	152401500	2437400	(591100)	(26529800)
26	1500	23700	2992900	5.00	118500	2874400	155275900	2315200	(559200)	(27089000)
27	1500	23700	2838700	5.00	118500	2720200	157996100	2193000	(527200)	(27616200)
28	1500	23700	2684500	5.00	118500	2566000	160562100	2070800	(495200)	(28111400)
29	1500	23700	2530300	5.00	118500	2411800	162973900	1948700	(463100)	(28574500)
30	1500	23700	2376200	5.00	118500	2257700	165231600	1826500	(431200)	(29005700)
TOT	127500	2011500	178601100		13369500	165231600		136225900	(29005700)	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						6.91		5.70		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						2.59		2.14		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						65952600		54984900	(10967700)	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						2.76		2.30		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						1.03		0.86		

Table A-123

MAGNESIA SCHEME B, REGULATED POWER CO. ECONOMICS, 500 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 22237000

Includes comparison with projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	110400	9474700	8.00	883200	8591500	8591500	9115900	524400	524400
2	7000	110400	9320500	8.00	883200	8437300	17028800	9016300	579000	1103400
3	7000	110400	9166400	8.00	883200	8283200	25312000	8916700	633500	1736900
4	7000	110400	9012200	8.00	883200	8129000	33441000	8817100	688100	2425000
5	7000	110400	8858000	8.00	883200	7974800	41415800	8717600	742800	3167800
6	7000	110400	8703800	8.00	883200	7820600	49236400	8618000	797400	3965200
7	7000	110400	8549700	8.00	883200	7666500	56902900	8518400	851900	4817100
8	7000	110400	8395500	8.00	883200	7512300	64415200	8418800	906500	5723600
9	7000	110400	8241300	8.00	883200	7358100	71773300	8319200	961100	6684700
10	7000	110400	8087200	8.00	883200	7204000	78977300	8219600	1015600	7700300
11	5000	78900	7053700	5.00	394500	6659200	85636500	6719600	60400	7760700
12	5000	78900	6899500	5.00	394500	6505000	92141500	6620000	115000	7875700
13	5000	78900	6745400	5.00	394500	6350900	98492400	6520400	169500	8045200
14	5000	78900	6591200	5.00	394500	6196700	104689100	6420800	224100	8269300
15	5000	78900	6437000	5.00	394500	6042500	110731600	6321200	278700	8548000
16	3500	55200	5581500	5.00	276000	5305500	116037100	5139500	(166000)	8382000
17	3500	55200	5427300	5.00	276000	5151300	121188400	5039900	(111400)	8270600
18	3500	55200	5273100	5.00	276000	4997100	126185500	4940300	(56800)	8213800
19	3500	55200	5118900	5.00	276000	4842900	131028400	4840700	(2200)	8211600
20	3500	55200	4964800	5.00	276000	4688800	135717200	4741100	52300	8263900
21	1500	23700	3763700	5.00	118500	3645200	139362400	3114300	(530900)	7733000
22	1500	23700	3609500	5.00	118500	3491000	142853400	3014700	(476300)	7256700
23	1500	23700	3455400	5.00	118500	3336900	146190300	2915100	(421800)	6834900
24	1500	23700	3301200	5.00	118500	3182700	149373000	2815500	(367200)	6467700
25	1500	23700	3147000	5.00	118500	3028500	152401500	2715900	(312600)	6155100
26	1500	23700	2992900	5.00	118500	2874400	155275900	2616400	(258000)	5897100
27	1500	23700	2838700	5.00	118500	2720200	157996100	2516800	(203400)	5693700
28	1500	23700	2684500	5.00	118500	2566000	160562100	2417200	(148800)	5544900
29	1500	23700	2530300	5.00	118500	2411800	162973900	2317600	(94200)	5450700
30	1500	23700	2376200	5.00	118500	2257700	165231600	2218000	(39700)	5411000
TOT	127500	2011500	178601100		13369500	165231600		170642600	5411000	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						6.91		7.14		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						2.59		2.68		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						65952600		70296800	4344200	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						2.76		2.94		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						1.03		1.10		

Table A-124

MAGNESIA SCHEME B, REGULATED POWER CO. ECONOMICS, 1000 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 33838000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	213500	14324000	8.00	1708000	12616000	12616000	11082800	(1533200)	(1533200)
2	7000	213500	14089400	8.00	1708000	12381400	24997400	10892700	(1488700)	(3021900)
3	7000	213500	13854800	8.00	1708000	12146800	37144200	10702700	(1444100)	(4466000)
4	7000	213500	13620200	8.00	1708000	11912200	49056400	10512600	(1399600)	(5865600)
5	7000	213500	13385600	8.00	1708000	11677600	60734000	10322500	(1355100)	(7220700)
6	7000	213500	13151000	8.00	1708000	11443000	72177000	10132500	(1310500)	(8531200)
7	7000	213500	12916400	8.00	1708000	11208400	83385400	9942400	(1266000)	(9797200)
8	7000	213500	12681800	8.00	1708000	10973800	94359200	9752300	(1221500)	(11018700)
9	7000	213500	12447200	8.00	1708000	10739200	105098400	9562200	(1177000)	(12195700)
10	7000	213500	12212600	8.00	1708000	10504600	115603000	9372200	(1132400)	(13328100)
11	5000	152500	10609200	5.00	762500	9846700	125449700	8236300	(1610400)	(14938500)
12	5000	152500	10374600	5.00	762500	9612100	135061800	8046200	(1565900)	(16504400)
13	5000	152500	10140000	5.00	762500	9377500	144439300	7856200	(1521300)	(18025700)
14	5000	152500	9905400	5.00	762500	9142900	153582200	7666100	(1476800)	(19502500)
15	5000	152500	9670800	5.00	762500	8908300	162490500	7476000	(1432300)	(20934800)
16	3500	106800	8356000	5.00	534000	7822000	170312500	6530600	(1291400)	(22226200)
17	3500	106800	8121400	5.00	534000	7587400	177899900	6340600	(1246800)	(23473000)
18	3500	106800	7886700	5.00	534000	7352700	185252600	6150500	(1202200)	(24675200)
19	3500	106800	7652100	5.00	534000	7118100	192370700	5960400	(1157700)	(25832900)
20	3500	106800	7417500	5.00	534000	6883500	199254200	5770400	(1113100)	(26946000)
21	1500	45800	5603000	5.00	229000	5374000	204628200	4451700	(922300)	(27868300)
22	1500	45800	5368400	5.00	229000	5139400	209767600	4261600	(877800)	(28746100)
23	1500	45800	5133800	5.00	229000	4904800	214672400	4071600	(833200)	(29579300)
24	1500	45800	4899200	5.00	229000	4670200	219342600	3881500	(788700)	(30368000)
25	1500	45800	4664600	5.00	229000	4435600	223778200	3691400	(744200)	(31112200)
26	1500	45800	4430000	5.00	229000	4201000	227979200	3501300	(699700)	(31811900)
27	1500	45800	4195400	5.00	229000	3966400	231945600	3311300	(655100)	(32467000)
28	1500	45800	3960800	5.00	229000	3731800	235677400	3121200	(610600)	(33077600)
29	1500	45800	3726200	5.00	229000	3497200	239174600	2931100	(566100)	(33643700)
30	1500	45800	3491600	5.00	229000	3262600	242437200	2741100	(521500)	(34165200)
TOT	127500	3889500	268289700		25852500	242437200		208272000	(34165200)	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						5.25		4.51		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						1.90		1.63		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						96743000		84316100	(12426900)	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						2.09		1.82		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.76		0.66		

Table A-125

MAGNESIA SCHEME B, REGULATED POWER CO. ECONOMICS, 200 MW. NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 6806000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	24100	2982400	8.00	192800	2789600	2789600	2429700	(359900)	(359900)
2	7000	24100	2935300	8.00	192800	2742500	5532100	2390200	(352300)	(712200)
3	7000	24100	2888100	8.00	192800	2695300	8227400	2350700	(344600)	(1056800)
4	7000	24100	2840900	8.00	192800	2648100	10875500	2311100	(337000)	(1393800)
5	7000	24100	2793700	8.00	192800	2600900	13476400	2271600	(329300)	(1723100)
6	7000	24100	2746500	8.00	192800	2553700	16030100	2232100	(321600)	(2044700)
7	7000	24100	2699300	8.00	192800	2506500	18536600	2192600	(313900)	(2358600)
8	7000	24100	2652100	8.00	192800	2459300	20995900	2153100	(306200)	(2664800)
9	7000	24100	2604900	8.00	192800	2412100	23408000	2113500	(298600)	(2963400)
10	7000	24100	2557700	8.00	192800	2364900	25772900	2074000	(290900)	(3254300)
11	5000	17200	2243800	5.00	86000	2157800	27930700	1826600	(331200)	(3585500)
12	5000	17200	2196600	5.00	86000	2110600	30041300	1787100	(323500)	(3909000)
13	5000	17200	2149400	5.00	86000	2063400	32104700	1747600	(315800)	(4224800)
14	5000	17200	2102200	5.00	86000	2016200	34120900	1708000	(308200)	(4533000)
15	5000	17200	2055000	5.00	86000	1969000	36089900	1668500	(300500)	(4833500)
16	3500	12000	1790000	5.00	60000	1730000	37819900	1459000	(271000)	(5104500)
17	3500	12000	1742800	5.00	60000	1682800	39502700	1419500	(263300)	(5367800)
18	3500	12000	1695600	5.00	60000	1635600	41138300	1380000	(255600)	(5623400)
19	3500	12000	1648400	5.00	60000	1588400	42726700	1340400	(248000)	(5871400)
20	3500	12000	1601200	5.00	60000	1541200	44267900	1300900	(240300)	(6111700)
21	1500	5200	1217700	5.00	26000	1191700	45459600	997500	(194200)	(6305900)
22	1500	5200	1170500	5.00	26000	1144500	46604100	958000	(186500)	(6492400)
23	1500	5200	1123400	5.00	26000	1097400	47701500	918500	(178900)	(6671300)
24	1500	5200	1076200	5.00	26000	1050200	48751700	878900	(171300)	(6842600)
25	1500	5200	1029000	5.00	26000	1003000	49754700	839400	(163600)	(7006200)
26	1500	5200	981800	5.00	26000	955800	50710500	799900	(155900)	(7162100)
27	1500	5200	934600	5.00	26000	908600	51619100	760400	(148200)	(7310300)
28	1500	5200	887400	5.00	26000	861400	52480500	720900	(140500)	(7450800)
29	1500	5200	840200	5.00	26000	814200	53294700	681300	(132900)	(7583700)
30	1500	5200	793000	5.00	26000	767000	54061700	641800	(125200)	(7708900)
TOT	127500	439000	56979700		2918000	54061700		46352800	(7708900)	
EQUIVALENT COST, DOLLARS PER BARREL OF OIL BURNED						1.44		1.24		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						2.12		1.82		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						21510000		18625500	(2884500)	
EQUIVALENT PRESENT WORTH, DOLLARS PER BARREL OF OIL BURNED						0.57		0.50		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.84		0.73		

Table A-126

MAGNESIA SCHEME B, REGULATED POWER CO. ECONOMICS, 500 MW. NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 12561000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	58900	5359900	8.00	471200	4888700	4888700	4454500	(434200)	(434200)
2	7000	58900	5272800	8.00	471200	4801600	9690300	4308500	(493100)	(927300)
3	7000	58900	5185700	8.00	471200	4714500	14404800	4306400	(408100)	(1335400)
4	7000	58900	5098600	8.00	471200	4627400	19032200	4232400	(395000)	(1730400)
5	7000	58900	5011500	8.00	471200	4540300	23572500	4158300	(382000)	(2112400)
6	7000	58900	4924400	8.00	471200	4453200	28025700	4084300	(368900)	(2481300)
7	7000	58900	4837400	8.00	471200	4366200	32391900	4010200	(356000)	(2837300)
8	7000	58900	4750300	8.00	471200	4279100	36671000	3936200	(342900)	(3180200)
9	7000	58900	4663200	8.00	471200	4192000	40863000	3862100	(329900)	(3510100)
10	7000	58900	4576100	8.00	471200	4104900	44967900	3786100	(316800)	(3826900)
11	5000	42100	4000500	5.00	210500	3790000	48757900	3325700	(464300)	(4291200)
12	5000	42100	3913400	5.00	210500	3702900	52460800	3251600	(451300)	(4742500)
13	5000	42100	3826300	5.00	210500	3615800	56076600	3177600	(438200)	(5180700)
14	5000	42100	3739200	5.00	210500	3528700	59605300	3103500	(425200)	(5605900)
15	5000	42100	3652100	5.00	210500	3441600	63046900	3029500	(412100)	(6018000)
16	3500	29400	3173100	5.00	147000	3026100	66073000	2642700	(383400)	(6401400)
17	3500	29400	3086100	5.00	147000	2939100	69012100	2568700	(370400)	(6771800)
18	3500	29400	2999000	5.00	147000	2852000	71864100	2494600	(357400)	(7129200)
19	3500	29400	2911900	5.00	147000	2764900	74629000	2420600	(344300)	(7473500)
20	3500	29400	2824800	5.00	147000	2677800	77306800	2346500	(331300)	(7804800)
21	1500	12600	2147600	5.00	63000	2084600	79391400	1798300	(286300)	(8091100)
22	1500	12600	2060500	5.00	63000	1997500	81388900	1724200	(273300)	(8364400)
23	1500	12600	1973400	5.00	63000	1910400	83299300	1650200	(260200)	(8624600)
24	1500	12600	1886300	5.00	63000	1823300	85122600	1576100	(247200)	(8871800)
25	1500	12600	1799200	5.00	63000	1736200	86858800	1502100	(234100)	(9105900)
26	1500	12600	1712100	5.00	63000	1649100	88507900	1428000	(221100)	(9327000)
27	1500	12600	1625100	5.00	63000	1562100	90070000	1354000	(208100)	(9535100)
28	1500	12600	1538000	5.00	63000	1475000	91545000	1279900	(195100)	(9730200)
29	1500	12600	1450900	5.00	63000	1387900	92932900	1205900	(182000)	(9912200)
30	1500	12600	1363800	5.00	63000	1300800	94233700	1131900	(169000)	(10081200)
TOT	127500	1072500	101363200		7129500	94233700		84152500	(10081200)	
EQUIVALENT COST, DOLLARS PER BARREL OF OIL BURNED						1.03		0.92		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						1.48		1.32		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						37564700		33948200	(3616500)	
EQUIVALENT PRESENT WORTH, DOLLARS PER BARREL OF OIL BURNED						0.41		0.37		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.59		0.53		

Table A-127

MAGNESIA SCHEME B, REGULATED POWER CO. ECONOMICS, 500 MW. NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 12561000

Includes comparison with projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	58900	5359900	8.00	471200	4888700	4888700	5015800	127100	127100
2	7000	58900	5272800	8.00	471200	4801600	9690300	4955600	154000	281100
3	7000	58900	5135700	8.00	471200	4714500	14404800	4895400	180900	462000
4	7000	58900	5098600	8.00	471200	4627400	19032200	4835200	207800	669800
5	7000	58900	5011500	8.00	471200	4540300	23572500	4775000	234700	904500
6	7000	58900	4924400	8.00	471200	4453200	28025700	4714800	261600	1166100
7	7000	58900	4837400	8.00	471200	4366200	32391900	4654600	288400	1454500
8	7000	58900	4750300	8.00	471200	4279100	36671000	4594400	315300	1769800
9	7000	58900	4663200	8.00	471200	4192000	40863000	4534200	342200	2112000
10	7000	58900	4576100	8.00	471200	4104900	44967900	4474000	369100	2481100
11	5000	42100	4000500	5.00	210500	3790000	48757900	3712000	(78000)	2403100
12	5000	42100	3913400	5.00	210500	3702900	52460800	3651800	(51100)	2352000
13	5000	42100	3826300	5.00	210500	3615800	56076600	3591600	(24200)	2327800
14	5000	42100	3739200	5.00	210500	3528700	59605300	3531400	2700	2330500
15	5000	42100	3652100	5.00	210500	3441600	63046900	3471200	29600	2360100
16	3500	29400	3173100	5.00	147000	3026100	66073000	2865100	(161000)	2199100
17	3500	29400	3086100	5.00	147000	2939100	69012100	2804900	(134200)	2064900
18	3500	29400	2999000	5.00	147000	2852000	71864100	2744700	(107300)	1957600
19	3500	29400	2911900	5.00	147000	2764900	74629000	2684600	(80300)	1877300
20	3500	29400	2824800	5.00	147000	2677800	77306800	2624400	(53400)	1823900
21	1500	12600	2147600	5.00	63000	2084600	79391400	1783400	(301200)	1522700
22	1500	12600	2060500	5.00	63000	1997500	81388900	1723200	(274300)	1248400
23	1500	12600	1973400	5.00	63000	1910400	83299300	1663000	(247400)	1001000
24	1500	12600	1886300	5.00	63000	1823300	85122600	1602800	(220500)	780500
25	1500	12600	1799200	5.00	63000	1736200	86858800	1542600	(193600)	586900
26	1500	12600	1712100	5.00	63000	1649100	88507900	1482400	(166700)	420200
27	1500	12600	1625100	5.00	63000	1562100	90070000	1422200	(139900)	280300
28	1500	12600	1538000	5.00	63000	1475000	91545000	1362000	(113000)	167300
29	1500	12600	1450900	5.00	63000	1387900	92932900	1301800	(86100)	81200
30	1500	12600	1363800	5.00	63000	1300800	94233700	1241600	(59200)	22000
TOT	127500	1072500	101363200		7129500	94233700		94255700	22000	
EQUIVALENT COST, DOLLARS PER BARREL OF OIL BURNED						1.03		1.03		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						1.48		1.48		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						37564700		38632900	1068200	
EQUIVALENT PRESENT WORTH, DOLLARS PER BARREL OF OIL BURNED						0.41		0.42		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.59		0.61		

Table A-128

MAGNESIA SCHEME B, REGULATED POWER CO. ECONOMICS, 1000 MW. NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 19126000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
		100% H2SO4		100% H2SO4						
1	7000	113900	8115900	8.00	911200	7204700	7204700	6890400	(314300)	(314300)
2	7000	113900	7983300	8.00	911200	7072100	14276800	6775100	(297000)	(611300)
3	7000	113900	7850700	8.00	911200	6939500	21216300	6659800	(279700)	(891000)
4	7000	113900	7718100	8.00	911200	6806900	28023200	6544500	(262400)	(1153400)
5	7000	113900	7585500	8.00	911200	6674300	34697500	6429300	(245000)	(1398400)
6	7000	113900	7452900	8.00	911200	6541700	41239200	6314000	(227700)	(1626100)
7	7000	113900	7320300	8.00	911200	6409100	47648300	6198700	(210400)	(1836500)
8	7000	113900	7187700	8.00	911200	6276500	53924800	6083400	(193100)	(2029600)
9	7000	113900	7055100	8.00	911200	6143900	60068700	5968100	(175800)	(2205400)
10	7000	113900	6922500	8.00	911200	6011300	66080000	5852800	(158500)	(2363900)
11	5000	81300	6022800	5.00	406500	5616300	71696300	5120700	(495600)	(2859500)
12	5000	81300	5890200	5.00	406500	5483700	77180000	5005400	(478300)	(3337800)
13	5000	81300	5757600	5.00	406500	5351100	82531100	4890100	(461000)	(3798800)
14	5000	81300	5625000	5.00	406500	5218500	87749600	4774800	(443700)	(4242500)
15	5000	81300	5492400	5.00	406500	5085900	92835500	4659500	(426400)	(4668900)
16	3500	56900	4752400	5.00	284500	4467900	97303400	4052800	(415100)	(5084000)
17	3500	56900	4619800	5.00	284500	4335300	101638700	3937500	(397800)	(5481800)
18	3500	56900	4487200	5.00	284500	4202700	105841400	3822200	(380500)	(5862300)
19	3500	56900	4354600	5.00	284500	4070100	109911500	3706900	(363200)	(6225500)
20	3500	56900	4222000	5.00	284500	3937500	113849000	3591600	(345900)	(6571400)
21	1500	24400	3194900	5.00	122000	3072900	116921900	2745400	(327500)	(6898900)
22	1500	24400	3062300	5.00	122000	2940300	119862200	2630100	(310200)	(7209100)
23	1500	24400	2929700	5.00	122000	2807700	122669900	2514900	(292800)	(7501900)
24	1500	24400	2797100	5.00	122000	2675100	125345000	2399600	(275500)	(7777400)
25	1500	24400	2664500	5.00	122000	2542500	127887500	2284300	(258200)	(8035600)
26	1500	24400	2531900	5.00	122000	2409900	130297400	2169000	(240900)	(8276500)
27	1500	24400	2399300	5.00	122000	2277300	132574700	2053700	(223600)	(8500100)
28	1500	24400	2266700	5.00	122000	2144700	134719400	1938400	(206300)	(8706400)
29	1500	24400	2134100	5.00	122000	2012100	136731500	1823100	(189000)	(8895400)
30	1500	24400	2001500	5.00	122000	1879500	138611000	1707800	(171700)	(9067100)
TOT	127500	2074000	152398000		13787000	138611000		129543900	(9067100)	
EQUIVALENT COST, DOLLARS PER BARREL OF OIL BURNED						0.78		0.73		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						1.09		1.02		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						55284000		52482200	(2801900)	
EQUIVALENT PRESENT WORTH, DOLLARS PER BARREL OF OIL BURNED						0.31		0.30		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.43		0.41		

Table A-129

MAGNESIA SCHEME C, REGULATED POWER CO. ECONOMICS, 200 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 9923000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	38700	4421800	8.00	309600	4112200	4112200	3825400	(286800)	(286800)
2	7000	38700	4353000	8.00	309600	4043400	8155600	3761700	(281700)	(568500)
3	7000	38700	4284200	8.00	309600	3974600	12130200	3698000	(276600)	(845100)
4	7000	38700	4215400	8.00	309600	3905800	16036000	3634200	(271600)	(1116700)
5	7000	38700	4146600	8.00	309600	3837000	19873000	3570500	(266500)	(1383200)
6	7000	38700	4077800	8.00	309600	3768200	23641200	3506800	(261400)	(1644600)
7	7000	38700	4008900	8.00	309600	3699300	27340500	3443000	(256300)	(1900900)
8	7000	38700	3940100	8.00	309600	3630500	30971000	3379300	(251200)	(2152100)
9	7000	38700	3871300	8.00	309600	3561700	34532700	3315600	(246100)	(2398200)
10	7000	38700	3802500	8.00	309600	3492900	38025600	3251900	(241000)	(2639200)
11	5000	27700	3312800	5.00	138500	3174300	41199900	2868100	(306200)	(2945400)
12	5000	27700	3244000	5.00	138500	3105500	44305400	2804400	(301100)	(3246500)
13	5000	27700	3175200	5.00	138500	3036700	47342100	2740700	(296000)	(3542500)
14	5000	27700	3106400	5.00	138500	2967900	50310000	2676900	(291000)	(3833500)
15	5000	27700	3037600	5.00	138500	2899100	53209100	2613200	(285900)	(4119400)
16	3500	19400	2629000	5.00	97000	2532000	55741100	2288900	(243100)	(4362500)
17	3500	19400	2560200	5.00	97000	2463200	58204300	2225100	(238100)	(4600600)
18	3500	19400	2491400	5.00	97000	2394400	60598700	2161400	(233000)	(4833600)
19	3500	19400	2422600	5.00	97000	2325600	62924300	2097700	(227900)	(5061500)
20	3500	19400	2353800	5.00	97000	2256800	65181100	2033900	(222900)	(5284400)
21	1500	8300	1769900	5.00	41500	1728400	66909500	1567700	(160700)	(5445100)
22	1500	8300	1701000	5.00	41500	1659500	68569000	1504000	(155500)	(5600600)
23	1500	8300	1632200	5.00	41500	1590700	70159700	1440200	(150500)	(5751100)
24	1500	8300	1563400	5.00	41500	1521900	71681600	1376500	(145400)	(5896500)
25	1500	8300	1494600	5.00	41500	1453100	73134700	1312800	(140300)	(6036800)
26	1500	8300	1425800	5.00	41500	1384300	74519000	1249100	(135200)	(6172000)
27	1500	8300	1357000	5.00	41500	1315500	75834500	1185300	(130200)	(6302200)
28	1500	8300	1288200	5.00	41500	1246700	77081200	1121600	(125100)	(6427300)
29	1500	8300	1219400	5.00	41500	1177900	78259100	1057900	(120000)	(6547300)
30	1500	8300	1150600	5.00	41500	1109100	79368200	994100	(115000)	(6662300)
TOT	127500	765500	84056700		4688500	79368200		72705900	(6662300)	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						8.12		7.44		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						3.11		2.85		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						31679000		29257300	(2421700)	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						3.24		2.99		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						1.24		1.15		

Table A-130

MAGNESIA SCHEME C, REGULATED POWER CO. ECONOMICS, 500 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 18111000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	94700	7979000	8.00	757600	7221400	7221400	7209600	(11800)	(11800)
2	7000	94700	7853400	8.00	757600	7095800	14317200	7087400	(8400)	(20200)
3	7000	94700	7727800	8.00	757600	6970200	21287400	6965200	(5000)	(25200)
4	7000	94700	7602300	8.00	757600	6844700	28132100	6843000	(1700)	(26900)
5	7000	94700	7476700	8.00	757600	6719100	34851200	6720900	1800	(25100)
6	7000	94700	7351100	8.00	757600	6593500	41444700	6598700	5200	(19900)
7	7000	94700	7225600	8.00	757600	6468000	47912700	6476500	8500	(11400)
8	7000	94700	7100000	8.00	757600	6342400	54255100	6354300	11900	500
9	7000	94700	6974400	8.00	757600	6216800	60471900	6232100	15300	15800
10	7000	94700	6848900	8.00	757600	6091300	66563200	6110000	18700	34500
11	5000	67600	5939700	5.00	338000	5601700	72164900	5381100	(220600)	(186100)
12	5000	67600	5814100	5.00	338000	5476100	77641000	5258900	(217200)	(403300)
13	5000	67600	5688600	5.00	338000	5350600	82991600	5136700	(213900)	(617200)
14	5000	67600	5563000	5.00	338000	5225000	88216600	5014500	(210500)	(827700)
15	5000	67600	5437400	5.00	338000	5099400	93316000	4892400	(207000)	(1034700)
16	3500	47300	4688500	5.00	236500	4452000	97768000	4280700	(171300)	(1206000)
17	3500	47300	4563000	5.00	236500	4326500	102094500	4158500	(168000)	(1374000)
18	3500	47300	4437400	5.00	236500	4200900	106295400	4036300	(164600)	(1538600)
19	3500	47300	4311800	5.00	236500	4075300	110370700	3914200	(161100)	(1699700)
20	3500	47300	4186300	5.00	236500	3949800	114320500	3792000	(157800)	(1857500)
21	1500	20300	3135500	5.00	101500	3034000	117354500	2926100	(107900)	(1965400)
22	1500	20300	3009900	5.00	101500	2908400	120262900	2803900	(104500)	(2069900)
23	1500	20300	2884400	5.00	101500	2782900	123045800	2681700	(101200)	(2171100)
24	1500	20300	2758800	5.00	101500	2657300	125703100	2559600	(97700)	(2268800)
25	1500	20300	2633200	5.00	101500	2531700	128234800	2437400	(94300)	(2363100)
26	1500	20300	2507600	5.00	101500	2406100	130640900	2315200	(90900)	(2454000)
27	1500	20300	2382100	5.00	101500	2280600	132921500	2193000	(87600)	(2541600)
28	1500	20300	2256500	5.00	101500	2155000	135076500	2070800	(84200)	(2625800)
29	1500	20300	2130900	5.00	101500	2029400	137105900	1948700	(80700)	(2706500)
30	1500	20300	2005400	5.00	101500	1903900	139009800	1826500	(77400)	(2783900)
TOT	127500	1724500	150473300		11463500	139009800		136225900	(2783900)	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						5.81		5.70		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						2.18		2.14		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						55530300		54984900	(545400)	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						2.32		2.30		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.87		0.86		

Table A-131

MAGNESIA SCHEME C, REGULATED POWER CO. ECONOMICS, 500 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 18111000

Includes comparison with projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	94700	7979000	8.00	757600	7221400	7221400	9115900	1894500	1894500
2	7000	94700	7853400	8.00	757600	7095800	14317200	9016300	1920500	3815000
3	7000	94700	7727800	9.00	757600	6970200	21287400	8916700	1946500	5761500
4	7000	94700	7602300	8.00	757600	6844700	28132100	8817100	1972400	7733900
5	7000	94700	7476700	8.00	757600	6719100	34851200	8717600	1998500	9732400
6	7000	94700	7351100	8.00	757600	6593500	41444700	8618000	2024500	11756900
7	7000	94700	7225600	6.00	757600	6468000	47912700	8518400	2050400	13807300
8	7000	94700	7100000	8.00	757600	6342400	54255100	8419800	2076400	15983700
9	7000	94700	6974400	8.00	757600	6216800	60471900	8319200	2102400	17986100
10	7000	94700	6848900	8.00	757600	6091300	66563200	8219600	2128300	20114400
11	5000	67600	5939700	5.00	338000	5601700	72164900	6719600	1117900	21232300
12	5000	67600	5814100	5.00	338000	5476100	77641000	6620000	1143900	22376200
13	5000	67600	5688600	5.00	338000	5350600	82991600	6520400	1169800	23546000
14	5000	67600	5563000	5.00	338000	5225000	88216600	6420800	1195800	24741800
15	5000	67600	5437400	5.00	338000	5099400	93316000	6321200	1221800	25963600
16	3500	47300	4688500	5.00	236500	4452000	97768000	5139500	687500	26651100
17	3500	47300	4563000	5.00	236500	4326500	102094500	5039900	713400	27364500
18	3500	47300	4437400	5.00	236500	4200900	106295400	4940300	739400	28103900
19	3500	47300	4311800	5.00	236500	4075300	110370700	4840700	765400	28869300
20	3500	47300	4186300	5.00	236500	3949800	114320500	4741100	791300	29660600
21	1500	20300	3135500	5.00	101500	3034000	117354500	3114300	80300	29740900
22	1500	20300	3009900	5.00	101500	2908400	120262900	3014700	106300	29847200
23	1500	20300	2884400	5.00	101500	2782900	123045800	2915100	132200	29979400
24	1500	20300	2758800	5.00	101500	2657300	125703100	2815500	158200	30137600
25	1500	20300	2633200	5.00	101500	2531700	128234800	2715900	184200	30321800
26	1500	20300	2507600	5.00	101500	2406100	130640900	2616400	210300	30532100
27	1500	20300	2382100	5.00	101500	2280600	132921500	2516800	236200	30768300
28	1500	2030C	2256500	5.00	101500	2155000	135076500	2417200	262200	31030500
29	1500	20300	2130900	5.00	101500	2029400	137105900	2317600	288200	31318700
30	1500	20300	2005400	5.00	101500	1903900	139009800	2218000	314100	31632800
TOT	127500	1724500	150473300		11463500	139009800		170642600	31632800	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						5.81		7.14		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						2.18		2.68		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						55530300		70296800	14766500	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						2.32		2.94		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.87		1.10		

Table A-132

MAGNESIA SCHEME C, REGULATED POWER CO. ECONOMICS, 1000 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT: $ 27540000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	183000	12058100	8.00	1464000	10594100	10594100	11082800	488700	488700
2	7000	183000	11867200	8.00	1464000	10403200	20997300	10892700	489500	978200
3	7000	183000	11676200	8.00	1464000	10212700	31209500	10702700	490500	1468700
4	7000	183000	11485300	8.00	1464000	10021300	41230800	10512600	491300	1960000
5	7000	183000	11294300	8.00	1464000	9830300	51061100	10322500	492200	2452200
6	7000	183000	11103400	8.00	1464000	9639400	60700500	10132500	493100	2945300
7	7000	183000	10912500	8.00	1464000	9448500	70149000	9942400	493900	3439200
8	7000	183000	10721500	8.00	1464000	9257500	79406500	9752300	494800	3934000
9	7000	183000	10530600	8.00	1464000	9066600	88473100	9562200	495600	4429600
10	7000	183000	10339600	8.00	1464000	8875600	97348700	9372200	496600	4926200
11	5000	130700	8929600	5.00	653500	8276100	105624800	8236300	(39800)	4886400
12	5000	130700	8738600	5.00	653500	8085100	113709900	8046200	(38900)	4847500
13	5000	130700	8547700	5.00	653500	7894200	121604100	7856200	(38000)	4809500
14	5000	130700	8356700	5.00	653500	7703200	129307300	7666100	(37100)	4772400
15	5000	130700	8165800	5.00	653500	7512300	136819600	7476000	(36300)	4736100
16	3500	91500	7015400	5.00	457500	6557900	143377500	6530600	(27300)	4708800
17	3500	91500	6824400	5.00	457500	6366900	149744400	6340600	(26300)	4682500
18	3500	91500	6633500	5.00	457500	6176000	155920400	6150500	(25500)	4657000
19	3500	91500	6442500	5.00	457500	5985000	161905400	5960400	(24600)	4632400
20	3500	91500	6251600	5.00	457500	5794100	167699500	5770400	(23700)	4608700
21	1500	39200	4663000	5.00	196000	4467000	172166500	4451700	(15300)	4593400
22	1500	39200	4472100	5.00	196000	4276100	176442600	4261600	(14500)	4578900
23	1500	39200	4281200	5.00	196000	4085200	180527800	4071600	(13600)	4565300
24	1500	39200	4090200	5.00	196000	3894200	184422000	3881500	(12700)	4552600
25	1500	39200	3899300	5.00	196000	3703300	188125300	3691400	(11900)	4540700
26	1500	39200	3708300	5.00	196000	3512300	191637600	3501300	(11000)	4529700
27	1500	39200	3517400	5.00	196000	3321400	194959000	3311300	(10100)	4519600
28	1500	39200	3326400	5.00	196000	3130400	198089400	3121200	(9200)	4510400
29	1500	39200	3135500	5.00	196000	2939500	201028900	2931100	(8400)	4502000
30	1500	39200	2944500	5.00	196000	2748500	203777400	2741100	(7400)	4494600
TOT	127500	3333000	225932400		22155000	203777400		208272000	4494600	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						4.41		4.51		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						1.60		1.63		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						81383500		84316100	2932600	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						1.76		1.82		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.64		0.66		

Table A-133

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 200 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 11685000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 7.4%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	45200	3468400	3825400 (	357000)	3468400	8.00	361600
2	7000	45200	3468400	3761700 (	293300)	3468400	8.00	361600
3	7000	45200	3468400	3698000 (	229600)	3468400	8.00	361600
4	7000	45200	3468400	3634200 (	165800)	3468400	8.00	361600
5	7000	45200	3468400	3570500 (	102100)	3468400	8.00	361600
6	7000	45200	3468400	3506800 (	38400)	3468400	8.00	361600
7	7000	45200	3468400	3443000	25400	3468400	8.00	361600
8	7000	45200	3468400	3379300	89100	3468400	8.00	361600
9	7000	45200	3468400	3315600	152800	3468400	8.00	361600
10	7000	45200	3468400	3251900	216500	3468400	8.00	361600
11	5000	32300	1846700	2868100 (	1021400)	1846700	5.00	161500
12	5000	32300	1846700	2804400 (	957700)	1846700	5.00	161500
13	5000	32300	1846700	2740700 (	894000)	1846700	5.00	161500
14	5000	32300	1846700	2676900 (	830200)	1846700	5.00	161500
15	5000	32300	1846700	2613200 (	766500)	1846700	5.00	161500
16	3500	22600	1480900	2288900 (	808000)	1480900	5.00	113000
17	3500	22600	1480900	2225100 (	744200)	1480900	5.00	113000
18	3500	22600	1480900	2161400 (	680500)	1480900	5.00	113000
19	3500	22600	1480900	2097700 (	616800)	1480900	5.00	113000
20	3500	22600	1480900	2033900 (	553000)	1480900	5.00	113000
21	1500	9700	923700	1567700 (	644000)	923700	5.00	48500
22	1500	9700	923700	1504000 (	580300)	923700	5.00	48500
23	1500	9700	923700	1440200 (	516500)	923700	5.00	48500
24	1500	9700	923700	1376500 (	452800)	923700	5.00	48500
25	1500	9700	923700	1312800 (	389100)	923700	5.00	48500
26	1500	9700	923700	1249100 (	325400)	923700	5.00	48500
27	1500	9700	923700	1185300 (	261600)	923700	5.00	48500
28	1500	9700	923700	1121600 (	197900)	923700	5.00	48500
29	1500	9700	923700	1057900 (	134200)	923700	5.00	48500
30	1500	9700	923700	994100 (	70400)	923700	5.00	48500
TOT	127500	823500	60559000	72705900 (	1214690)	60559000		5473500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 8.3
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	718600 (	3106800)	359300 (	1553400)	1527800 (	384900)	1527800 (	384900)	3.00	
2	654900 (	3106800)	327450 (	1553400)	1495950 (	384900)	3023750 (	769800)	2.74	
3	591200 (	3106800)	295600 (	1553400)	1464100 (	384900)	4487850 (	1154700)	2.47	
4	527400 (	3106800)	263700 (	1553400)	1432200 (	384900)	5920050 (	1539600)	2.20	
5	463700 (	3106800)	231850 (	1553400)	1400350 (	384900)	7320400 (	1924500)	1.94	
6	400000 (	3106800)	200000 (	1553400)	1368500 (	384900)	8688900 (	2309400)	1.67	
7	336200 (	3106800)	168100 (	1553400)	1336600 (	384900)	10025500 (	2694300)	1.40	
8	272500 (	3106800)	136250 (	1553400)	1304750 (	384900)	11330250 (	3079200)	1.14	
9	208800 (	3106800)	104400 (	1553400)	1272900 (	384900)	12603150 (	3464100)	0.87	
10	145100 (	3106800)	72550 (	1553400)	1241050 (	384900)	13844200 (	3849000)	0.61	
11	1182900 (	1685200)	591450 (	842600)	591450 (	842600)	14435650 (	4691600)	4.97	
12	1119200 (	1685200)	559600 (	842600)	559600 (	842600)	14995250 (	5534200)	4.70	
13	1055500 (	1685200)	527750 (	842600)	527750 (	842600)	15523000 (	6376800)	4.43	
14	991700 (	1685200)	495850 (	842600)	495850 (	842600)	16018850 (	7219400)	4.17	
15	928000 (	1685200)	464000 (	842600)	464000 (	842600)	16482850 (	8062000)	3.90	
16	921000 (	1367900)	460500 (	683950)	460500 (	683950)	16943350 (	8745950)	3.88	
17	857200 (	1367900)	428600 (	683950)	428600 (	683950)	17371950 (	9429900)	3.62	
18	793500 (	1367900)	396750 (	683950)	396750 (	683950)	17768700 (	10113850)	3.35	
19	729800 (	1367900)	364900 (	683950)	364900 (	683950)	18133600 (	10797800)	3.08	
20	666000 (	1367900)	333000 (	683950)	333000 (	683950)	18466600 (	11481750)	2.81	
21	692500 (	875200)	346250 (	437600)	346250 (	437600)	18812850 (	11919350)	2.94	
22	628800 (	875200)	314400 (	437600)	314400 (	437600)	19127250 (	12356950)	2.67	
23	565000 (	875200)	282500 (	437600)	282500 (	437600)	19409750 (	12794550)	2.40	
24	501300 (	875200)	250650 (	437600)	250650 (	437600)	19660400 (	13232150)	2.13	
25	437600 (	875200)	218800 (	437600)	218800 (	437600)	19879200 (	13669750)	1.86	
26	373900 (	875200)	186950 (	437600)	186950 (	437600)	20066150 (	14107350)	1.59	
27	310100 (	875200)	155050 (	437600)	155050 (	437600)	20221200 (	14544950)	1.32	
28	246400 (	875200)	123200 (	437600)	123200 (	437600)	20344400 (	14982550)	1.05	
29	182700 (	875200)	91350 (	437600)	91350 (	437600)	20435750 (	15420150)	0.78	
30	118900 (	875200)	59450 (	437600)	59450 (	437600)	20495200 (	15857750)	0.50	
TOT	17620400 (	55085500)	8810200 (	27542750)	20495200 (	15857750)			AVG= 2.49	

Table A-134

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 200 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 11685000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 11.0%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	45200	3468400	4388700 (	920300)	3468400	8.00	361600
2	7000	45200	3468400	4338300 (	869900)	3468400	8.00	361600
3	7000	45200	3468400	4288000 (	819600)	3468400	8.00	361600
4	7000	45200	3468400	4237700 (	769300)	3468400	8.00	361600
5	7000	45200	3468400	4187300 (	718900)	3468400	8.00	361600
6	7000	45200	3468400	4137000 (	668600)	3468400	8.00	361600
7	7000	45200	3468400	4086700 (	618300)	3468400	8.00	361600
8	7000	45200	3468400	4036300 (	567900)	3468400	8.00	361600
9	7000	45200	3468400	3986000 (	517600)	3468400	8.00	361600
10	7000	45200	3468400	3935700 (	467300)	3468400	8.00	361600
11	5000	32300	1846700	3252900 (	1406200)	1846700	5.00	161500
12	5000	32300	1846700	3202600 (	1355900)	1846700	5.00	161500
13	5000	32300	1846700	3152200 (	1305500)	1846700	5.00	161500
14	5000	32300	1846700	3101900 (	1255200)	1846700	5.00	161500
15	5000	32300	1846700	3051600 (	1204900)	1846700	5.00	161500
16	3500	22600	1480900	2508100 (	1027200)	1480900	5.00	113000
17	3500	22600	1480900	2457800 (	976900)	1480900	5.00	113000
18	3500	22600	1480900	2407500 (	926600)	1480900	5.00	113000
19	3500	22600	1480900	2357100 (	876200)	1480900	5.00	113000
20	3500	22600	1480900	2306800 (	825900)	1480900	5.00	113000
21	1500	9700	923700	1550300 (	626600)	923700	5.00	48500
22	1500	9700	923700	1499900 (	576200)	923700	5.00	48500
23	1500	9700	923700	1449600 (	525900)	923700	5.00	48500
24	1500	9700	923700	1399300 (	475600)	923700	5.00	48500
25	1500	9700	923700	1348900 (	425200)	923700	5.00	48500
26	1500	9700	923700	1298600 (	374900)	923700	5.00	48500
27	1500	9700	923700	1248200 (	324500)	923700	5.00	48500
28	1500	9700	923700	1197900 (	274200)	923700	5.00	48500
29	1500	9700	923700	1147600 (	223900)	923700	5.00	48500
30	1500	9700	923700	1097200 (	173500)	923700	5.00	48500
TOT	127500	823500	60559000	82657700 (	22098700)	60559000		5473500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 6.7
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	1281900	(3106800)	640950	(1553400)	1809450	(384900)	1809450	(384900)	5.36	
2	1231500	(3106800)	615750	(1553400)	1784250	(384900)	3593700	(769800)	5.15	
3	1181200	(3106800)	590600	(1553400)	1759100	(384900)	5352800	(1154700)	4.94	
4	1130900	(3106800)	565450	(1553400)	1733950	(384900)	7086750	(1539600)	4.73	
5	1080500	(3106800)	540250	(1553400)	1708750	(384900)	8795500	(1924500)	4.51	
6	1030200	(3106800)	515100	(1553400)	1683600	(384900)	10479100	(2309400)	4.30	
7	979900	(3106800)	489950	(1553400)	1658450	(384900)	12137550	(2694300)	4.09	
8	929500	(3106800)	464750	(1553400)	1633250	(384900)	13770800	(3079200)	3.88	
9	879200	(3106800)	439600	(1553400)	1608100	(384900)	15378900	(3464100)	3.67	
10	828900	(3106800)	414450	(1553400)	1582950	(384900)	16961850	(3849000)	3.46	
11	1567700	(1685200)	783850	(842600)	783850	(842600)	17745700	(4691600)	6.58	
12	1517400	(1685200)	758700	(842600)	758700	(842600)	18504400	(5534200)	6.37	
13	1467000	(1685200)	733500	(842600)	733500	(842600)	19237900	(6376800)	6.16	
14	1416700	(1685200)	708350	(842600)	708350	(842600)	19946250	(7219400)	5.95	
15	1366400	(1685200)	683200	(842600)	683200	(842600)	20629450	(8062000)	5.74	
16	1140200	(1367900)	570100	(683950)	570100	(683950)	21199550	(8745950)	4.81	
17	1089900	(1367900)	544950	(683950)	544950	(683950)	21744500	(9429900)	4.60	
18	1039600	(1367900)	519800	(683950)	519800	(683950)	22264300	(10113850)	4.38	
19	989200	(1367900)	494600	(683950)	494600	(683950)	22758900	(10797800)	4.17	
20	938900	(1367900)	469450	(683950)	469450	(683950)	23228350	(11481750)	3.96	
21	675100	(875200)	337550	(437600)	337550	(437600)	23565900	(11919350)	2.87	
22	624700	(875200)	312350	(437600)	312350	(437600)	23878250	(12356950)	2.65	
23	574400	(875200)	287200	(437600)	287200	(437600)	24165450	(12794550)	2.44	
24	524100	(875200)	262050	(437600)	262050	(437600)	24427500	(13232150)	2.22	
25	473700	(875200)	236850	(437600)	236850	(437600)	24664350	(13669750)	2.01	
26	423400	(875200)	211700	(437600)	211700	(437600)	24876050	(14107350)	1.80	
27	373000	(875200)	186500	(437600)	186500	(437600)	25062550	(14544950)	1.58	
28	322700	(875200)	161350	(437600)	161350	(437600)	25223900	(14982550)	1.37	
29	272400	(875200)	136200	(437600)	136200	(437600)	25360100	(15420150)	1.16	
30	222000	(875200)	111000	(437600)	111000	(437600)	25471100	(15857750)	0.94	
TOT	27572200	(55085500)	13786100	(27542750)	25471100	(15857750)		AVG=	3.90	

Table A-135

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 200 MW. EXISTING COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 13083000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 6.6%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1								
2								
3								
4								
5								
6								
7								
8								
9	7000	46600	3746400	4276000	(529600)	3746400	8.00	372800
10	7000	46600	3746400	4179500	(433100)	3746400	8.00	372800
11	5000	33300	3274600	3741100	(466500)	3274600	8.00	266400
12	5000	33300	3274600	3644600	(370000)	3274600	8.00	266400
13	5000	33300	3274600	3548100	(273500)	3274600	8.00	266400
14	5000	33300	3274600	3451600	(177000)	3274600	8.00	266400
15	5000	33300	3274600	3355100	(80500)	3274600	8.00	266400
16	3500	23300	2892200	2979200	(87000)	2892200	8.00	186400
17	3500	23300	2892200	2882700	9500	2892200	8.00	186400
18	3500	23300	2892200	2786200	106000	2892200	8.00	186400
19	3500	23300	1583900	2689700	(1105800)	1583900	5.00	116500
20	3500	23300	1583900	2593100	(1009200)	1583900	5.00	116500
21	1500	10000	998000	2064200	(1066200)	998000	5.00	50000
22	1500	10000	998000	1967700	(969700)	998000	5.00	50000
23	1500	10000	998000	1871200	(873200)	998000	5.00	50000
24	1500	10000	998000	1774700	(776700)	998000	5.00	50000
25	1500	10000	998000	1678200	(680200)	998000	5.00	50000
26	1500	10000	998000	1581700	(583700)	998000	5.00	50000
27	1500	10000	998000	1485200	(487200)	998000	5.00	50000
28	1500	10000	998000	1388600	(390600)	998000	5.00	50000
29	1500	10000	998000	1292100	(294100)	998000	5.00	50000
30	1500	10000	998000	1195600	(197600)	998000	5.00	50000
TOT	71500	476200	45690200	56426100	(10735900)	45690200		3369800

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 8.2
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1										
2										
3										
4										
5										
6										
7										
8										
9	902400	(3373600)	451200	(1686800)	1759500	(378500)	1759500	(378500)	3.37	
10	805900	(3373600)	402950	(1686800)	1711250	(378500)	3470750	(757000)	3.01	
11	732900	(3008200)	366450	(1504100)	1674750	(195800)	5145500	(952800)	2.75	
12	636400	(3008200)	318200	(1504100)	1626500	(195800)	6772000	(1148600)	2.39	
13	539900	(3008200)	269950	(1504100)	1578250	(195800)	8350250	(1344400)	2.03	
14	443400	(3008200)	221700	(1504100)	1530000	(195800)	9880250	(1540200)	1.67	
15	346900	(3008200)	173450	(1504100)	1481750	(195800)	11362000	(1736000)	1.30	
16	273400	(2705800)	136700	(1352900)	1445000	(44600)	12807000	(1780600)	1.03	
17	176900	(2705800)	88450	(1352900)	1396750	(44600)	14203750	(1825200)	0.67	
18	80400	(2705800)	40200	(1352900)	1348500	(44600)	15552250	(1869800)	0.30	
19	1222300	(1467400)	611150	(733700)	611150	(733700)	16163400	(2603500)	4.61	
20	1125700	(1467400)	562850	(733700)	562850	(733700)	16726250	(3337200)	4.24	
21	1116200	(948000)	558100	(474000)	558100	(474000)	17284350	(3811200)	4.23	
22	1019700	(948000)	509850	(474000)	509850	(474000)	17794200	(4285200)	3.87	
23	923200	(948000)	461600	(474000)	461600	(474000)	18255800	(4759200)	3.50	
24	826700	(948000)	413350	(474000)	413350	(474000)	18669150	(5233200)	3.14	
25	730200	(948000)	365100	(474000)	365100	(474000)	19034250	(5707200)	2.77	
26	633700	(948000)	316850	(474000)	316850	(474000)	19351100	(6181200)	2.40	
27	537200	(948000)	268600	(474000)	268600	(474000)	19619700	(6655200)	2.04	
28	440600	(948000)	220300	(474000)	220300	(474000)	19840000	(7129200)	1.67	
29	344100	(948000)	172050	(474000)	172050	(474000)	20012050	(7603200)	1.31	
30	247600	(948000)	123800	(474000)	123800	(474000)	20135850	(8077200)	0.94	
TOT	14105700	(42320400)	7052850	(21160200)	20135850	(8077200)			AVG= 2.43	

Table A-136

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 500 MW. NEW COAL FIRED POWER PLANT, 2.0 % S IN FUEL, 98% H_2SO_4 PRODUCTION.

FIXED INVESTMENT = $ 18788000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 9.5%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H_2SO_4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H_2SO_4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	63100	5276300	6483500 (	1207200)	5276300	8.00	504800
2	7000	63100	5276300	6371300 (	1095000)	5276300	8.00	504800
3	7000	63100	5276300	6259200 (	982900)	5276300	8.00	504800
4	7000	63100	5276300	6147100 (	870800)	5276300	8.00	504800
5	7000	63100	5276300	6034900 (	758600)	5276300	8.00	504800
6	7000	63100	5276300	5922800 (	646500)	5276300	8.00	504800
7	7000	63100	5276300	5810700 (	534400)	5276300	8.00	504800
8	7000	63100	5276300	5698500 (	422200)	5276300	8.00	504800
9	7000	63100	5276300	5586400 (	310100)	5276300	8.00	504800
10	7000	63100	5276300	5474300 (	198000)	5276300	8.00	504800
11	5000	45100	2714000	4840900 (	2126900)	2714000	5.00	225500
12	5000	45100	2714000	4728800 (	2014800)	2714000	5.00	225500
13	5000	45100	2714000	4616700 (	1902700)	2714000	5.00	225500
14	5000	45100	2714000	4504500 (	1790500)	2714000	5.00	225500
15	5000	45100	2714000	4392600 (	1678600)	2714000	5.00	225500
16	3500	31600	2166600	3858100 (	1691500)	2166600	5.00	158000
17	3500	31600	2166600	3746000 (	1579400)	2166600	5.00	158000
18	3500	31600	2166600	3633800 (	1467200)	2166600	5.00	158000
19	3500	31600	2166600	3521700 (	1355100)	2166600	5.00	158000
20	3500	31600	2166600	3409600 (	1243000)	2166600	5.00	158000
21	1500	13500	1346200	2651800 (	1305600)	1346200	5.00	67500
22	1500	13500	1346200	2539700 (	1193500)	1346200	5.00	67500
23	1500	13500	1346200	2427600 (	1081400)	1346200	5.00	67500
24	1500	13500	1346200	2315400 (	969200)	1346200	5.00	67500
25	1500	13500	1346200	2203300 (	857100)	1346200	5.00	67500
26	1500	13500	1346200	2091200 (	745000)	1346200	5.00	67500
27	1500	13500	1346200	1979000 (	632800)	1346200	5.00	67500
28	1500	13500	1346200	1866900 (	520700)	1346200	5.00	67500
29	1500	13500	1346200	1754800 (	408600)	1346200	5.00	67500
30	1500	13500	1346200	1642600 (	296400)	1346200	5.00	67500
TOT	127500	1149500	90628000	122513500 (	31885500)	90628000		7640500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 7.4
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	1712000	(4771500)	856000	(2385750)	2734800	(506950)	2734800	(506950)	4.46	
2	1599800	(4771500)	799900	(2385750)	2678700	(506950)	5413500	(1013900)	4.17	
3	1487700	(4771500)	743850	(2385750)	2622650	(506950)	8036150	(1520850)	3.87	
4	1375600	(4771500)	687800	(2385750)	2566600	(506950)	10602750	(2027800)	3.58	
5	1263400	(4771500)	631700	(2385750)	2510500	(506950)	13113250	(2534750)	3.29	
6	1151300	(4771500)	575650	(2385750)	2454450	(506950)	15567700	(3041700)	3.00	
7	1039200	(4771500)	519600	(2385750)	2398400	(506950)	17966100	(3548650)	2.71	
8	927000	(4771500)	463500	(2385750)	2342300	(506950)	20308400	(4055600)	2.41	
9	814900	(4771500)	407450	(2385750)	2286250	(506950)	22594650	(4562550)	2.12	
10	702800	(4771500)	351400	(2385750)	2230200	(506950)	24824850	(5069500)	1.83	
11	2352400	(2488500)	1176200	(1244250)	1176200	(1244250)	26001050	(6313750)	6.16	
12	2240300	(2488500)	1120150	(1244250)	1120150	(1244250)	27121200	(7558000)	5.86	
13	2128200	(2488500)	1064100	(1244250)	1064100	(1244250)	28185300	(8802250)	5.57	
14	2016000	(2488500)	1008000	(1244250)	1008000	(1244250)	29193300	(10046500)	5.28	
15	1903900	(2488500)	951950	(1244250)	951950	(1244250)	30145250	(11290750)	4.98	
16	1849500	(2008600)	924750	(1004300)	924750	(1004300)	31070000	(12295050)	4.86	
17	1737400	(2008600)	868700	(1004300)	868700	(1004300)	31938700	(13299350)	4.56	
18	1625200	(2008600)	812600	(1004300)	812600	(1004300)	32751300	(14303650)	4.27	
19	1513100	(2008600)	756550	(1004300)	756550	(1004300)	33507850	(15307950)	3.98	
20	1401000	(2008600)	700500	(1004300)	700500	(1004300)	34208350	(16312250)	3.68	
21	1373100	(1278700)	686550	(639350)	686550	(639350)	34894900	(16951600)	3.63	
22	1261000	(1278700)	630500	(639350)	630500	(639350)	35525400	(17590950)	3.33	
23	1148900	(1278700)	574450	(639350)	574450	(639350)	36099850	(18230300)	3.04	
24	1036700	(1278700)	518350	(639350)	518350	(639350)	36618200	(18869650)	2.74	
25	924600	(1278700)	462300	(639350)	462300	(639350)	37080500	(19509000)	2.44	
26	812500	(1278700)	406250	(639350)	406250	(639350)	37486750	(20148350)	2.15	
27	700300	(1278700)	350150	(639350)	350150	(639350)	37836900	(20787700)	1.85	
28	588200	(1278700)	294100	(639350)	294100	(639350)	38131000	(21427050)	1.55	
29	476100	(1278700)	238050	(639350)	238050	(639350)	38369050	(22066400)	1.26	
30	363900	(1278700)	181950	(639350)	181950	(639350)	38551000	(22705750)	0.96	
TOT	39526900	(82987500)	19763000	(41493750)	38551000	(22705750)			AVG= 3.48	

Table A-137

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 900 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 21732000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 8.8%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR		NET REVENUE, $/TON	TOTAL NET SALES REVENUE, $/YEAR
		100% H2SO4			WITH PAYMENT	WITHOUT PAYMENT	100% H2SO4	
1	7000	110400	6306400	7209600	(903200)	6306400	8.00	883200
2	7000	110400	6306400	7087400	(781000)	6306400	8.00	883200
3	7000	110400	6306400	6965200	(658800)	6306400	8.00	883200
4	7000	110400	6306400	6843000	(536600)	6306400	8.00	883200
5	7000	110400	6306400	6720900	(414500)	6306400	8.00	883200
6	7000	110400	6306400	6598700	(292300)	6306400	8.00	883200
7	7000	110400	6306400	6476500	(170100)	6306400	8.00	883200
8	7000	110400	6306400	6354300	(47900)	6306400	8.00	883200
9	7000	110400	6306400	6232100	74300	6306400	8.00	883200
10	7000	110400	6306400	6110000	196400	6306400	8.00	883200
11	5000	78900	3286000	5381100	(2095100)	3286000	5.00	394500
12	5000	78900	3286000	5258900	(1972900)	3286000	5.00	394500
13	5000	78900	3286000	5136700	(1850700)	3286000	5.00	394500
14	5000	78900	3286000	5014500	(1728500)	3286000	5.00	394500
15	5000	78900	3286000	4892300	(1606300)	3286000	5.00	394500
16	3500	55200	2610400	4280700	(1670300)	2610400	5.00	276000
17	3500	55200	2610400	4158500	(1548100)	2610400	5.00	276000
18	3500	55200	2610400	4036300	(1425900)	2610400	5.00	276000
19	3500	55200	2610400	3914200	(1303800)	2610400	5.00	276000
20	3500	55200	2610400	3792000	(1181600)	2610400	5.00	276000
21	1500	23700	1603800	2926200	(1322300)	1603800	5.00	118500
22	1500	23700	1603800	2803900	(1200100)	1603800	5.00	118500
23	1500	23700	1603800	2681700	(1077900)	1603800	5.00	118500
24	1500	23700	1603800	2559600	(955800)	1603800	5.00	118500
25	1500	23700	1603800	2437400	(833600)	1603800	5.00	118500
26	1500	23700	1603800	2315200	(711400)	1603800	5.00	118500
27	1500	23700	1603800	2193000	(589200)	1603800	5.00	118500
28	1500	23700	1603800	2070800	(467000)	1603800	5.00	118500
29	1500	23700	1603800	1948700	(344900)	1603800	5.00	118500
30	1500	23700	1603800	1826500	(222700)	1603800	5.00	118500
TOT	127500	2011500	108584000	136275900	(27641900)	108584000		13369500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 7.6
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR		NET INCOME AFTER TAXES, $/YEAR		CASH FLOW, $/YEAR		CUMULATIVE CASH FLOW, $		ANNUAL RETURN ON INITIAL INVESTMENT, %	
	WITH PAYMENT	WITHOUT PAYMENT	WITH PAYMENT	WITHOUT PAYMENT	WITH PAYMENT	WITHOUT PAYMENT	WITH PAYMENT	WITHOUT PAYMENT	WITH PAYMENT	WITHOUT PAYMENT
1	1786400	(5423200)	893200	(2711600)	3066400	(538400)	3066400	(538400)	4.02	
2	1664200	(5423200)	832100	(2711600)	3005300	(538400)	6071700	(1076800)	3.74	
3	1542000	(5423200)	771000	(2711600)	2944200	(538400)	9015900	(1615200)	3.47	
4	1419800	(5423200)	709900	(2711600)	2883100	(538400)	11899000	(2153600)	3.19	
5	1297700	(5423200)	648850	(2711600)	2822050	(538400)	14721050	(2692000)	2.92	
6	1175500	(5423200)	587750	(2711600)	2760950	(538400)	17482000	(3230400)	2.64	
7	1053300	(5423200)	526650	(2711600)	2699850	(538400)	20181850	(3768800)	2.37	
8	931100	(5423200)	465550	(2711600)	2638750	(538400)	22820600	(4307200)	2.09	
9	808900	(5423200)	404450	(2711600)	2577650	(538400)	25398250	(4845600)	1.82	
10	686800	(5423200)	343400	(2711600)	2516600	(538400)	27914850	(5384000)	1.55	
11	2489600	(2891500)	1244800	(1445750)	1244800	(1445750)	29159650	(6829750)	5.63	
12	2367400	(2891500)	1183700	(1445750)	1183700	(1445750)	30343350	(8275500)	5.35	
13	2245200	(2891500)	1122600	(1445750)	1122600	(1445750)	31465950	(9721250)	5.07	
14	2123000	(2891500)	1061500	(1445750)	1061500	(1445750)	32527450	(11167000)	4.80	
15	2000900	(2891500)	1000450	(1445750)	1000450	(1445750)	33527900	(12612750)	4.52	
16	1946300	(2334400)	973150	(1167200)	973150	(1167200)	34501050	(13779950)	4.42	
17	1824100	(2334400)	912050	(1167200)	912050	(1167200)	35413100	(14947150)	4.14	
18	1701900	(2334400)	850950	(1167200)	850950	(1167200)	36264050	(16114350)	3.86	
19	1579800	(2334400)	789900	(1167200)	789900	(1167200)	37053950	(17281550)	3.59	
20	1457600	(2334400)	728800	(1167200)	728800	(1167200)	37782750	(18448750)	3.31	
21	1440800	(1485300)	720400	(742650)	720400	(742650)	38503150	(19191400)	3.29	
22	1318600	(1485300)	659300	(742650)	659300	(742650)	39162450	(19934050)	3.01	
23	1196400	(1485300)	598200	(742650)	598200	(742650)	39760650	(20676700)	2.73	
24	1074300	(1485300)	537150	(742650)	537150	(742650)	40297800	(21419350)	2.45	
25	952100	(1485300)	476050	(742650)	476050	(742650)	40773850	(22162000)	2.17	
26	829900	(1485300)	414950	(742650)	414950	(742650)	41188800	(22904650)	1.90	
27	707700	(1485300)	353850	(742650)	353850	(742650)	41542650	(23647300)	1.62	
28	585500	(1485300)	292750	(742650)	292750	(742650)	41835400	(24389950)	1.34	
29	463400	(1485300)	231700	(742650)	231700	(742650)	42067100	(25132600)	1.06	
30	341200	(1485300)	170600	(742650)	170600	(742650)	42237700	(25875250)	0.78	
TOT	41011400	(95214500)	20505700	(47607250)	42237700	(25875250)			AVG= 3.12	

Table A-138

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 500 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 21732000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 14.9%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	110400	6306400	9115900	(2809500)	6306400	8.00	883200
2	7000	110400	6306400	9016300	(2709900)	6306400	8.00	883200
3	7000	110400	6306400	8916700	(2610300)	6306400	8.00	883200
4	7000	110400	6306400	8817100	(2510700)	6306400	8.00	883200
5	7000	110400	6306400	8717600	(2411200)	6306400	8.00	883200
6	7000	110400	6306400	8618000	(2311600)	6306400	8.00	883200
7	7000	110400	6306400	8518400	(2212000)	6306400	8.00	883200
8	7000	110400	6306400	8418800	(2112400)	6306400	8.00	883200
9	7000	110400	6306400	8319200	(2012800)	6306400	8.00	883200
10	7000	110400	6306400	8219600	(1913200)	6306400	8.00	883200
11	5000	78900	3286000	6719600	(3433600)	3286000	5.00	394500
12	5000	78900	3286000	6620000	(3334000)	3286000	5.00	394500
13	5000	78900	3286000	6520400	(3234400)	3286000	5.00	394500
14	5000	78900	3286000	6420800	(3134800)	3286000	5.00	394500
15	5000	78900	3286000	6321200	(3035200)	3286000	5.00	394500
16	3500	55200	2610400	5139500	(2529100)	2610400	5.00	276000
17	3500	55200	2610400	5039900	(2429500)	2610400	5.00	276000
18	3500	55200	2610400	4940300	(2329900)	2610400	5.00	276000
19	3500	55200	2610400	4840700	(2230300)	2610400	5.00	276000
20	3500	55200	2610400	4741100	(2130700)	2610400	5.00	276000
21	1500	23700	1603800	3114300	(1510500)	1603800	5.00	118500
22	1500	23700	1603800	3014700	(1410900)	1603800	5.00	118500
23	1500	23700	1603800	2915100	(1311300)	1603800	5.00	118500
24	1500	23700	1603800	2815500	(1211700)	1603800	5.00	118500
25	1500	23700	1603800	2715900	(1112100)	1603800	5.00	118500
26	1500	23700	1603800	2616400	(1012600)	1603800	5.00	118500
27	1500	23700	1603800	2516800	(913000)	1603800	5.00	118500
28	1500	23700	1603800	2417200	(813400)	1603800	5.00	118500
29	1500	23700	1603800	2317600	(713800)	1603800	5.00	118500
30	1500	23700	1603800	2218000	(614200)	1603800	5.00	118500
TOT	127500	2011500	108584000	170642600	(62058600)	108584000		13369500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 5.6
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	3692700	(5423200)	1846350	(2711600)	4019550	(538400)	4019550	(538400)	8.30	
2	3593100	(5423200)	1796550	(2711600)	3969750	(538400)	7989300	(1076800)	8.08	
3	3493500	(5423200)	1746750	(2711600)	3919950	(538400)	11909250	(1615200)	7.85	
4	3393900	(5423200)	1696950	(2711600)	3870150	(538400)	15779400	(2153600)	7.63	
5	3294400	(5423200)	1647200	(2711600)	3820400	(538400)	19599800	(2692000)	7.41	
6	3194800	(5423200)	1597400	(2711600)	3770600	(538400)	23370400	(3230400)	7.18	
7	3095200	(5423200)	1547600	(2711600)	3720800	(538400)	27091200	(3768800)	6.96	
8	2995600	(5423200)	1497800	(2711600)	3671000	(538400)	30762200	(4307200)	6.74	
9	2896000	(5423200)	1448000	(2711600)	3621200	(538400)	34383400	(4845600)	6.51	
10	2796400	(5423200)	1398200	(2711600)	3571400	(538400)	37954800	(5384000)	6.29	
11	3828100	(2891500)	1914050	(1445750)	1914050	(1445750)	39868850	(6829750)	8.65	
12	3728500	(2891500)	1864250	(1445750)	1864250	(1445750)	41733100	(8275500)	8.43	
13	3628900	(2891500)	1814450	(1445750)	1814450	(1445750)	43547550	(9721250)	8.20	
14	3529300	(2891500)	1764650	(1445750)	1764650	(1445750)	45312200	(11167000)	7.98	
15	3429700	(2891500)	1714850	(1445750)	1714850	(1445750)	47027050	(12612750)	7.75	
16	2805100	(2334400)	1402550	(1167200)	1402550	(1167200)	48429600	(13779950)	6.37	
17	2705500	(2334400)	1352750	(1167200)	1352750	(1167200)	49782350	(14947150)	6.14	
18	2605900	(2334400)	1302950	(1167200)	1302950	(1167200)	51085300	(16114350)	5.91	
19	2506300	(2334400)	1253150	(1167200)	1253150	(1167200)	52338450	(17281550)	5.69	
20	2406700	(2334400)	1203350	(1167200)	1203350	(1167200)	53541800	(18448750)	5.46	
21	1629000	(1485300)	814500	(742650)	814500	(742650)	54356300	(19191400)	3.72	
22	1529400	(1485300)	764700	(742650)	764700	(742650)	55121000	(19934050)	3.49	
23	1429800	(1485300)	714900	(742650)	714900	(742650)	55835900	(20676700)	3.27	
24	1330200	(1485300)	665100	(742650)	665100	(742650)	56501000	(21419350)	3.04	
25	1230600	(1485300)	615300	(742650)	615300	(742650)	57116300	(22162000)	2.81	
26	1131100	(1485300)	565550	(742650)	565550	(742650)	57681850	(22904650)	2.58	
27	1031500	(1485300)	515750	(742650)	515750	(742650)	58197600	(23647300)	2.36	
28	931900	(1485300)	465950	(742650)	465950	(742650)	58663550	(24389950)	2.13	
29	832300	(1485300)	416150	(742650)	416150	(742650)	59079700	(25132600)	1.90	
30	732700	(1485300)	366350	(742650)	366350	(742650)	59446050	(25875250)	1.67	
TOT	75428100	(95214500)	37714050	(47607250)	59446050	(25875250)			AVG= 5.74	

Table A-139

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 500 MW, NEW COAL FIRED POWER PLANT, 5.0 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 24275000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 8.5%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	157800	7232500	7863100	(630600)	7232500	8.00	1262400
2	7000	157800	7232500	7731900	(499600)	7232500	8.00	1262400
3	7000	157800	7232500	7600700	(368200)	7232500	8.00	1262400
4	7000	157800	7232500	7469400	(236900)	7232500	8.00	1262400
5	7000	157800	7232500	7338200	(105700)	7232500	8.00	1262400
6	7000	157800	7232500	7207000	25500	7232500	8.00	1262400
7	7000	157800	7232500	7075800	156700	7232500	8.00	1262400
8	7000	157800	7232500	6944500	288000	7232500	8.00	1262400
9	7000	157800	7232500	6813300	419230	7232500	8.00	1262400
10	7000	157800	7232500	6682100	550400	7232500	8.00	1262400
11	5000	112700	3806900	5865300	(2058400)	3806900	5.00	563500
12	5000	112700	3806900	5734000	(1927100)	3806900	5.00	563500
13	5000	112700	3806900	5602800	(1795900)	3806900	5.00	563500
14	5000	112700	3806900	5471600	(1664700)	3806900	5.00	563500
15	5000	112700	3806900	5340300	(1533400)	3806900	5.00	563500
16	3500	78900	3013000	4657600	(1644600)	3013000	5.00	394500
17	3500	78900	3013000	4526400	(1513400)	3013000	5.00	394500
18	3500	78900	3013000	4395200	(1382200)	3013000	5.00	394500
19	3500	78900	3013000	4263900	(1250900)	3013000	5.00	394500
20	3500	78900	3013000	4132700	(1119700)	3013000	5.00	394500
21	1500	33800	1835800	3168900	(1333100)	1835800	5.00	169000
22	1500	33800	1835800	3037700	(1201900)	1835800	5.00	169000
23	1500	33800	1835800	2906400	(1070600)	1835800	5.00	169000
24	1500	33800	1835800	2775200	(939400)	1835800	5.00	169000
25	1500	33800	1835800	2644000	(808200)	1835800	5.00	169000
26	1500	33800	1835800	2512700	(676900)	1835800	5.00	169000
27	1500	33800	1835800	2381500	(545700)	1835800	5.00	169000
28	1500	33800	1835800	2250300	(414500)	1835800	5.00	169000
29	1500	33800	1835800	2119100	(283300)	1835800	5.00	169000
30	1500	33800	1835800	1987900	(152000)	1835800	5.00	169000
TOT	127500	2874000	124782500	148499400	(23716900)	124782500		19104000

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 7.7
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	1893000	(5970100)	946500	(2985050)	3374000	(557550)	3374000	(557550)	3.81	
2	1761900	(5970100)	880900	(2985050)	3308400	(557550)	6682400	(1115100)	3.54	
3	1630600	(5970100)	815300	(2985050)	3242800	(557550)	9925200	(1672650)	3.28	
4	1499300	(5970100)	749650	(2985050)	3177150	(557550)	13102350	(2230200)	3.01	
5	1368100	(5970100)	684050	(2985050)	3111550	(557550)	16213900	(2787750)	2.75	
6	1236900	(5970100)	618450	(2985050)	3045950	(557550)	19259850	(3345300)	2.49	
7	1105700	(5970100)	552850	(2985050)	2980350	(557550)	22240200	(3902850)	2.22	
8	974400	(5970100)	487200	(2985050)	2914750	(557550)	25154900	(4460400)	1.96	
9	843200	(5970100)	421600	(2985050)	[illegible]	(557550)	28004000	(5017950)	1.70	
10	712000	(5970100)	356000	(2985050)	2783500	(557550)	30787500	(5575500)	1.43	
11	2621900	(3243400)	1310950	(1621700)	1310950	(1621700)	32098450	(7197200)	5.30	
12	2490600	(3243400)	1245300	(1621700)	1245300	(1621700)	33343750	(8818900)	5.04	
13	2359400	(3243400)	1179700	(1621700)	1179700	(1621700)	34523450	(10440600)	4.77	
14	2228200	(3243400)	1114100	(1621700)	1114100	(1621700)	35637550	(12062300)	4.51	
15	2096900	(3243400)	1048450	(1621700)	1048450	(1621700)	36686000	(13684000)	4.25	
16	2039100	(2618500)	1019550	(1309250)	1019550	(1309250)	37705550	(14993250)	4.14	
17	1907900	(2618500)	953950	(1309250)	953950	(1309250)	38659500	(16302500)	3.87	
18	1776700	(2618500)	888350	(1309250)	888350	(1309250)	39547850	(17611750)	3.61	
19	1645400	(2618500)	822700	(1309250)	822700	(1309250)	40370550	(18921000)	3.34	
20	1514200	(2618500)	757100	(1309250)	757100	(1309250)	41127650	(20230250)	3.08	
21	1502100	(1666800)	751050	(833400)	751050	(833400)	41878700	(21063650)	3.07	
22	1370900	(1666800)	685450	(833400)	685450	(833400)	42564150	(21897050)	2.80	
23	1239600	(1666800)	619800	(833400)	619800	(833400)	43183950	(22730450)	2.53	
24	1108400	(1666800)	554200	(833400)	554200	(833400)	43738150	(23563850)	2.27	
25	977200	(1666800)	488600	(833400)	488600	(833400)	44226750	(24397250)	2.00	
26	845900	(1666800)	422950	(833400)	422950	(833400)	44649700	(25230650)	1.73	
27	714700	(1666800)	357350	(833400)	357350	(833400)	45007050	(26064050)	1.46	
28	583500	(1666800)	291750	(833400)	291750	(833400)	45298800	(26897450)	1.19	
29	452300	(1666800)	226150	(833400)	226150	(833400)	45524950	(27730850)	0.92	
30	321000	(1666800)	160500	(833400)	160500	(833400)	45685450	(28564250)	0.66	
TOT	42820900	(105678500)	21410450	(52839250)	45685450	(28564250)			AVG= 2.92	

Table A-140

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 500 MW. EXISTING COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 24646000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 8.4%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1								
2								
3								
4	7000	112900	6879300	7979600	(1100300)	6879300	8.00	903200
5	7000	112900	6879300	7827600	(948300)	6879300	8.00	903200
6	7000	112900	6879300	7675700	(796400)	6879300	8.00	903200
7	7000	112900	6879300	7523800	(644500)	6879300	8.00	903200
8	7000	112900	6879300	7371900	(492600)	6879300	8.00	903200
9	7000	112900	6879300	7220000	(340700)	6879300	8.00	903200
10	7000	112900	6879300	7068000	(188700)	6879300	8.00	903200
11	5000	80600	5991400	6270500	(279100)	5991400	8.00	644800
12	5000	80600	5991400	6118600	(127200)	5991400	8.00	644800
13	5000	80600	5991400	5966700	24700	5991400	8.00	644800
14	5000	80600	3526800	5814700	(2287900)	3526800	5.00	403000
15	5000	80600	3526800	5662800	(2136000)	3526800	5.00	403000
16	3500	56400	2815500	4988600	(2173100)	2815500	5.00	282000
17	3500	56400	2815500	4836700	(2021200)	2815500	5.00	282000
18	3500	56400	2815500	4684700	(1869200)	2815500	5.00	282000
19	3500	56400	2815500	4532800	(1717300)	2815500	5.00	282000
20	3500	56400	2815500	4380900	(1565400)	2815500	5.00	282000
21	1500	24200	1750300	3432400	(1682100)	1750300	5.00	121000
22	1500	24200	1750300	3280500	(1530200)	1750300	5.00	121000
23	1500	24200	1750300	3128500	(1378200)	1750300	5.00	121000
24	1500	24200	1750300	2976600	(1226300)	1750300	5.00	121000
25	1500	24200	1750300	2824700	(1074400)	1750300	5.00	121000
26	1500	24200	1750300	2672800	(922500)	1750300	5.00	121000
27	1500	24200	1750300	2520800	(770500)	1750300	5.00	121000
28	1500	24200	1750300	2368900	(618600)	1750300	5.00	121000
29	1500	24200	1750300	2217000	(466700)	1750300	5.00	121000
30	1500	24200	1750300	2065100	(314800)	1750300	5.00	121000
TOT	106500	1717300	104763400	133410900	(28647500)	104763400		11682800

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 7.7
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1										
2										
3										
4	2003500	(5976100)	1001750	(2988050)	3466350	(523450)	3466350	(523450)	3.98	
5	1851500	(5976100)	925750	(2988050)	3390350	(523450)	6856700	(1046900)	3.68	
6	1699600	(5976100)	849800	(2988050)	3314400	(523450)	10171100	(1570350)	3.37	
7	1547700	(5976100)	773850	(2988050)	3238450	(523450)	13409550	(2093800)	3.07	
8	1395800	(5976100)	697900	(2988050)	3162500	(523450)	16572050	(2617250)	2.77	
9	1243900	(5976100)	621950	(2988050)	3086550	(523450)	19658600	(3140700)	2.47	
10	1091900	(5976100)	545950	(2988050)	3010550	(523450)	22669150	(3664150)	2.17	
11	923900	(5346600)	461950	(2673300)	2926550	(208700)	25595700	(3872850)	1.86	
12	772000	(5346600)	386000	(2673300)	2850600	(208700)	28446300	(4081550)	1.56	
13	620100	(5346600)	310050	(2673300)	2774650	(208700)	31220950	(4290250)	1.26	
14	2690900	(3123800)	1345450	(1561900)	1345450	(1561900)	32566400	(5852150)	5.37	
15	2539000	(3123800)	1269500	(1561900)	1269500	(1561900)	33835900	(7414050)	5.07	
16	2455100	(2533500)	1227550	(1266750)	1227550	(1266750)	35063450	(8680800)	4.92	
17	2303200	(2533500)	1151600	(1266750)	1151600	(1266750)	36215050	(9947550)	4.61	
18	2151200	(2533500)	1075600	(1266750)	1075600	(1266750)	37290650	(11214300)	4.31	
19	1999300	(2533500)	999650	(1266750)	999650	(1266750)	38290300	(12481050)	4.00	
20	1847400	(2533500)	923700	(1266750)	923700	(1266750)	39214000	(13747800)	3.70	
21	1803100	(1629300)	901550	(814650)	901550	(814650)	40115550	(14562450)	3.63	
22	1651200	(1629300)	825600	(814650)	825600	(814650)	40941150	(15377100)	3.33	
23	1499200	(1629300)	749600	(814650)	749600	(814650)	41690750	(16191750)	3.02	
24	1347300	(1629300)	673650	(814650)	673650	(814650)	42364400	(17006400)	2.71	
25	1195400	(1629300)	597700	(814650)	597700	(814650)	42962100	(17821050)	2.41	
26	1043500	(1629300)	521750	(814650)	521750	(814650)	43483850	(18635700)	2.10	
27	891500	(1629300)	445750	(814650)	445750	(814650)	43929600	(19450350)	1.80	
28	739600	(1629300)	369800	(814650)	369800	(814650)	44299400	(20265000)	1.49	
29	587700	(1629300)	293850	(814650)	293850	(814650)	44593250	(21079650)	1.18	
30	435800	(1629300)	217900	(814650)	217900	(814650)	44811150	(21894300)	0.88	
TOT	40330300	(53880600)	20165150	(46540300)	44811150	(21894300)			AVG= 3.31	

Table A-141

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 1000 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 33118000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 10.0%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	213500	9508800	11082800	(1574000)	9508800	8.00	1708000
2	7000	213500	9508800	10892700	(1383900)	9508800	8.00	1708000
3	7000	213500	9508800	10702700	(1193900)	9508800	8.00	1708000
4	7000	213500	9508800	10512600	(1003800)	9508800	8.00	1708000
5	7000	213500	9508800	10322500	(813700)	9508800	8.00	1708000
6	7000	213500	9508800	10132500	(623700)	9508800	8.00	1708000
7	7000	213500	9508800	9942400	(433600)	9508800	8.00	1708000
8	7000	213500	9508800	9752300	(243500)	9508800	8.00	1708000
9	7000	213500	9508800	9562200	(53400)	9508800	8.00	1708000
10	7000	213500	9508800	9372200	136600	9508800	8.00	1708000
11	5000	152500	4880200	8236300	(3356100)	4880200	5.00	762500
12	5000	152500	4880200	8046200	(3166000)	4880200	5.00	762500
13	5000	152500	4880200	7856200	(2976000)	4880200	5.00	762500
14	5000	152500	4880200	7666100	(2785900)	4880200	5.00	762500
15	5000	152500	4880200	7476000	(2595800)	4880200	5.00	762500
16	3500	106800	3841300	6530600	(2689300)	3841300	5.00	534000
17	3500	106800	3841300	6340600	(2499300)	3841300	5.00	534000
18	3500	106800	3841300	6150500	(2309200)	3841300	5.00	534000
19	3500	106800	3841300	5960400	(2119100)	3841300	5.00	534000
20	3500	106800	3841300	5770400	(1929100)	3841300	5.00	534000
21	1500	45800	2323100	4451700	(2128600)	2323100	5.00	229000
22	1500	45800	2323100	4261600	(1938500)	2323100	5.00	229000
23	1500	45800	2323100	4071600	(1748500)	2323100	5.00	229000
24	1500	45800	2323100	3881500	(1558400)	2323100	5.00	229000
25	1500	45800	2323100	3691400	(1368300)	2323100	5.00	229000
26	1500	45800	2323100	3501300	(1178200)	2323100	5.00	229000
27	1500	45800	2323100	3311300	(988200)	2323100	5.00	229000
28	1500	45800	2323100	3121200	(798100)	2323100	5.00	229000
29	1500	45800	2323100	2931100	(608000)	2323100	5.00	229000
30	1500	45800	2323100	2741100	(418000)	2323100	5.00	229000
TOT	127500	3889500	161926500	208272000	(46345500)	161926500		25852500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 7.1
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	3282000	(7800800)	1641000	(3900400)	4952800	(588600)	4952800	(588600)	4.84	
2	3091900	(7800800)	1545950	(3900400)	4857750	(588600)	9810550	(1177200)	4.56	
3	2901900	(7800800)	1450950	(3900400)	4762750	(588600)	14573300	(1765800)	4.28	
4	2711800	(7800800)	1355900	(3900400)	4667700	(588600)	19241000	(2354400)	4.00	
5	2521700	(7800800)	1260850	(3900400)	4572650	(588600)	23813650	(2943000)	3.72	
6	2331700	(7800800)	1165850	(3900400)	4477650	(588600)	28291300	(3531600)	3.44	
7	2141600	(7800800)	1070800	(3900400)	4382600	(588600)	32673900	(4120200)	3.16	
8	1951500	(7800800)	975750	(3900400)	4287550	(588600)	36961450	(4708800)	2.88	
9	1761400	(7800800)	880700	(3900400)	4192500	(588600)	41153950	(5297400)	2.60	
10	1571400	(7800800)	785700	(3900400)	4097500	(588600)	45251450	(5886000)	2.32	
11	4118600	(4117700)	2059300	(2058850)	2059300	(2058850)	47310750	(7944850)	6.11	
12	3928500	(4117700)	1964250	(2058850)	1964250	(2058850)	49275000	(10003700)	5.83	
13	3738500	(4117700)	1869250	(2058850)	1869250	(2058850)	51144250	(12062550)	5.55	
14	3548400	(4117700)	1774200	(2058850)	1774200	(2058850)	52918450	(14121400)	5.27	
15	3358300	(4117700)	1679150	(2058850)	1679150	(2058850)	54597600	(16180250)	4.98	
16	3223300	(3307300)	1611650	(1653650)	1611650	(1653650)	56209250	(17833900)	4.80	
17	3033300	(3307300)	1516650	(1653650)	1516650	(1653650)	57725900	(19487550)	4.52	
18	2843200	(3307300)	1421600	(1653650)	1421600	(1653650)	59147500	(21141200)	4.24	
19	2653100	(3307300)	1326550	(1653650)	1326550	(1653650)	60474050	(22794850)	3.95	
20	2463100	(3307300)	1231550	(1653650)	1231550	(1653650)	61705600	(24448500)	3.67	
21	2357600	(2094100)	1178800	(1047050)	1178800	(1047050)	62884400	(25495550)	3.54	
22	2167500	(2094100)	1083750	(1047050)	1083750	(1047050)	63968150	(26542600)	3.25	
23	1977500	(2094100)	988750	(1047050)	988750	(1047050)	64956900	(27589650)	2.97	
24	1787400	(2094100)	893700	(1047050)	893700	(1047050)	65850600	(28636700)	2.68	
25	1597300	(2094100)	798650	(1047050)	798650	(1047050)	66649250	(29683750)	2.40	
26	1407200	(2094100)	703600	(1047050)	703600	(1047050)	67352850	(30730800)	2.11	
27	1217200	(2094100)	608600	(1047050)	608600	(1047050)	67961450	(31777850)	1.83	
28	1027100	(2094100)	513550	(1047050)	513550	(1047050)	68475000	(32824900)	1.54	
29	837000	(2094100)	418500	(1047050)	418500	(1047050)	68893500	(33871950)	1.26	
30	647000	(2094100)	323500	(1047050)	323500	(1047050)	69217000	(34919000)	0.97	
TOT	72198000	(136074000)	36099000	(68037000)	69217000	(34919000)			AVG= 3.61	

Table A-142

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 1000 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 33118000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 10.1%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	213500	9508800	15208800	(5700000)	9508800	8.00	1708000
2	7000	213500	9508800	15053700	(5544900)	9508800	8.00	1708000
3	7000	213500	9508800	14898600	(5389800)	9508800	8.00	1708000
4	7000	213500	9508800	14743500	(5234700)	9508800	8.00	1708000
5	7000	213500	9508800	14588400	(5079600)	9508800	8.00	1708000
6	7000	213500	9508800	14433200	(4924400)	9508800	8.00	1708000
7	7000	213500	9508800	14278100	(4769300)	9508800	8.00	1708000
8	7000	213500	9508800	14123000	(4614200)	9508800	8.00	1708000
9	7000	213500	9508800	13967900	(4459100)	9508800	8.00	1708000
10	7000	213500	9508800	13812800	(4304000)	9508800	8.00	1708000
11	5000	152500	4880200	11154900	(6274700)	4880200	5.00	762500
12	5000	152500	4880200	10999800	(6119600)	4880200	5.00	762500
13	5000	152500	4880200	10844700	(5964500)	4880200	5.00	762500
14	5000	152500	4880200	10689600	(5809400)	4880200	5.00	762500
15	5000	152500	4880200	10534500	(5654300)	4880200	5.00	762500
16	3500	106800	3841300	8458700	(4617400)	3841300	5.00	534000
17	3500	106800	3841300	8303600	(4462300)	3841300	5.00	534000
18	3500	106800	3841300	8148500	(4307200)	3841300	5.00	534000
19	3500	106800	3841300	7993400	(4152100)	3841300	5.00	534000
20	3500	106800	3841300	7838300	(3997000)	3841300	5.00	534000
21	1500	45800	2323100	5007900	(2684800)	2323100	5.00	229000
22	1500	45800	2323100	4852800	(2529700)	2323100	5.00	229000
23	1500	45800	2323100	4697700	(2374600)	2323100	5.00	229000
24	1500	45800	2323100	4542500	(2219400)	2323100	5.00	229000
25	1500	45800	2323100	4387400	(2064300)	2323100	5.00	229000
26	1500	45800	2323100	4232300	(1909200)	2323100	5.00	229000
27	1500	45800	2323100	4077200	(1754100)	2323100	5.00	229000
28	1500	45800	2323100	3922100	(1599000)	2323100	5.00	229000
29	1500	45800	2323100	3767000	(1443900)	2323100	5.00	229000
30	1500	45800	2323100	3611900	(1288800)	2323100	5.00	229000
TOT	127500	3889500	161926500	283172800	(121246300)	161926500		25852500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 4.6
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	7408000	(7800800)	3704000	(3900400)	7015800	(588600)	7015800	(588600)	10.93	
2	7252900	(7800800)	3626450	(3900400)	6938250	(588600)	13954050	(1177200)	10.70	
3	7097800	(7800800)	3548900	(3900400)	6860700	(588600)	20814750	(1765800)	10.48	
4	6942700	(7800800)	3471350	(3900400)	6783150	(588600)	27597900	(2354400)	10.25	
5	6787600	(7800800)	3393800	(3900400)	6705600	(588600)	34303500	(2943000)	10.02	
6	6632400	(7800800)	3316200	(3900400)	6628000	(588600)	40931500	(3531600)	9.79	
7	6477300	(7800800)	3238650	(3900400)	6550450	(588600)	47481950	(4120200)	9.56	
8	6322200	(7800800)	3161100	(3900400)	6472900	(588600)	53954850	(4708800)	9.33	
9	6167100	(7800800)	3083550	(3900400)	6395350	(588600)	60350200	(5297400)	9.10	
10	6012000	(7800800)	3006000	(3900400)	6317800	(588600)	66668000	(5886000)	8.87	
11	7037200	(4117700)	3518600	(2058850)	3518600	(2058850)	70186600	(7944850)	10.44	
12	6882100	(4117700)	3441050	(2058850)	3441050	(2058850)	73627650	(10003700)	10.21	
13	6727000	(4117700)	3363500	(2058850)	3363500	(2058850)	76991150	(12062550)	9.98	
14	6571900	(4117700)	3285950	(2058850)	3285950	(2058850)	80277100	(14121400)	9.75	
15	6416800	(4117700)	3208400	(2058850)	3208400	(2058850)	83485500	(16180250)	9.52	
16	5151400	(3307300)	2575700	(1653650)	2575700	(1653650)	86061200	(17833900)	7.68	
17	4996300	(3307300)	2498150	(1653650)	2498150	(1653650)	88559350	(19487550)	7.45	
18	4841200	(3307300)	2420600	(1653650)	2420600	(1653650)	90979950	(21141200)	7.21	
19	4686100	(3307300)	2343050	(1653650)	2343050	(1653650)	93323000	(22794850)	6.98	
20	4531000	(3307300)	2265500	(1653650)	2265500	(1653650)	95588500	(24448500)	6.75	
21	2913800	(2094100)	1456900	(1047050)	1456900	(1047050)	97045400	(25495550)	4.37	
22	2758700	(2094100)	1379350	(1047050)	1379350	(1047050)	98424750	(26542600)	4.14	
23	2603600	(2094100)	1301800	(1047050)	1301800	(1047050)	99726550	(27589650)	3.90	
24	2448400	(2094100)	1224200	(1047050)	1224200	(1047050)	100950750	(28636700)	3.67	
25	2293300	(2094100)	1146650	(1047050)	1146650	(1047050)	102097400	(29683750)	3.44	
26	2138200	(2094100)	1069100	(1047050)	1069100	(1047050)	103166500	(30730800)	3.21	
27	1983100	(2094100)	991550	(1047050)	991550	(1047050)	104158050	(31777850)	2.97	
28	1828000	(2094100)	914000	(1047050)	914000	(1047050)	105072050	(32824900)	2.74	
29	1672900	(2094100)	836450	(1047050)	836450	(1047050)	105908500	(33871950)	2.51	
30	1517800	(2094100)	758900	(1047050)	758900	(1047050)	106667400	(34919000)	2.28	
TOT	147098800	(136074000)	73549400	(68037000)	106667400	(34919000)			AVG= 7.35	

Table A-143

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 1000 MW. EXISTING COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 36634000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = -9.6%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1								
2								
3								
4	7000	220900	10185100	12063000	(1877900)	10185100	8.00	1767200
5	7000	220900	10185100	11834900	(1649800)	10185100	8.00	1767200
6	7000	220900	10185100	11606700	(1421600)	10185100	8.00	1767200
7	7000	220900	10185100	11378600	(1193500)	10185100	8.00	1767200
8	7000	220900	10185100	11150400	(965300)	10185100	8.00	1767200
9	7000	220900	10185100	10922200	(737100)	10185100	8.00	1767200
10	7000	220900	10185100	10694100	(509000)	10185100	8.00	1767200
11	5000	157800	8818400	9432700	(614300)	8818400	8.00	1262400
12	5000	157800	8818400	9204600	(386200)	8818400	8.00	1262400
13	5000	157800	8818400	8976400	(158000)	8818400	8.00	1262400
14	5000	157800	5155000	8748300	(3593300)	5155000	5.00	789000
15	5000	157800	5155000	8520100	(3365100)	5155000	5.00	789000
16	3500	110400	4074400	7467500	(3393100)	4074400	5.00	552000
17	3500	110400	4074400	7239300	(3164900)	4074400	5.00	552000
18	3500	110400	4074400	7011100	(2936700)	4074400	5.00	552000
19	3500	110400	4074400	6783000	(2708600)	4074400	5.00	552000
20	3500	110400	4074400	6554800	(2480400)	4074400	5.00	552000
21	1500	47300	2488700	5098000	(2609300)	2488700	5.00	236500
22	1500	47300	2488700	4869800	(2381100)	2488700	5.00	236500
23	1500	47300	2488700	4641700	(2153000)	2488700	5.00	236500
24	1500	47300	2488700	4413500	(1924800)	2488700	5.00	236500
25	1500	47300	2488700	4185400	(1696700)	2488700	5.00	236500
26	1500	47300	2488700	3957200	(1468500)	2488700	5.00	236500
27	1500	47300	2488700	3729100	(1240400)	2488700	5.00	236500
28	1500	47300	2488700	3500900	(1012200)	2488700	5.00	236500
29	1500	47300	2488700	3272700	(784000)	2488700	5.00	236500
30	1500	47300	2488700	3044600	(555900)	2488700	5.00	236500
TOT	106500	3360300	153319900	200300600	(46980700)	153319900		22860600

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 7.1
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1										
2										
3										
4	3645100	(8417900)	1822550	(4208950)	5485950	(545550)	5485950	(545550)	4.87	
5	3417000	(8417900)	1708500	(4208950)	5371900	(545550)	10857850	(1091100)	4.56	
6	3188800	(8417900)	1594400	(4208950)	5257800	(545550)	16115650	(1636650)	4.26	
7	2960700	(8417900)	1480350	(4208950)	5143750	(545550)	21259400	(2182200)	3.96	
8	2732500	(8417900)	1366250	(4208950)	5029650	(545550)	26289050	(2727750)	3.65	
9	2504300	(8417900)	1252150	(4208950)	4915550	(545550)	31204600	(3273300)	3.35	
10	2276200	(8417900)	1138100	(4208950)	4801500	(545550)	36006100	(3818850)	3.04	
11	1876700	(7556000)	938350	(3778000)	4601750	(114600)	40607850	(3933450)	2.52	
12	1648600	(7556000)	824300	(3778000)	4487700	(114600)	45095550	(4048050)	2.21	
13	1420400	(7556000)	710200	(3778000)	4373600	(114600)	49469150	(4162650)	1.91	
14	4382300	(4366000)	2191150	(2183000)	2191150	(2183000)	51660300	(6345650)	5.88	
15	4154100	(4366000)	2077050	(2183000)	2077050	(2183000)	53737350	(8528650)	5.58	
16	3945100	(3522400)	1972550	(1761200)	1972550	(1761200)	55709900	(10289850)	5.32	
17	3716900	(3522400)	1858450	(1761200)	1858450	(1761200)	57568350	(12051050)	5.01	
18	3488700	(3522400)	1744350	(1761200)	1744350	(1761200)	59312700	(13812250)	4.70	
19	3260600	(3522400)	1630300	(1761200)	1630300	(1761200)	60943000	(15573450)	4.40	
20	3032400	(3522400)	1516200	(1761200)	1516200	(1761200)	62459200	(17334650)	4.09	
21	2845800	(2252200)	1422900	(1126100)	1422900	(1126100)	63882100	(18460750)	3.86	
22	2617600	(2252200)	1308800	(1126100)	1308800	(1126100)	65190900	(19586850)	3.55	
23	2389500	(2252200)	1194750	(1126100)	1194750	(1126100)	66385650	(20712950)	3.24	
24	2161300	(2252200)	1080650	(1126100)	1080650	(1126100)	67466300	(21839050)	2.93	
25	1933200	(2252200)	966600	(1126100)	966600	(1126100)	68432900	(22965150)	2.62	
26	1705000	(2252200)	852500	(1126100)	852500	(1126100)	69285400	(24091250)	2.31	
27	1476900	(2252200)	738450	(1126100)	738450	(1126100)	70023850	(25217350)	2.00	
28	1248700	(2252200)	624350	(1126100)	624350	(1126100)	70648200	(26343450)	1.69	
29	1020500	(2252200)	510250	(1126100)	510250	(1126100)	71158450	(27469550)	1.38	
30	792400	(2252200)	396200	(1126100)	396200	(1126100)	71554650	(28595650)	1.07	
TOT	69841300	(130459300)	34920650	(65229650)	71554650	(28595650)			AVG= 3.91	

Table A-144

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 200 MW. NEW OIL FIRED POWER PLANT, 1.0 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 5148000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 11.8%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	9600	1547200	2114800	(567600)	1547200	8.00	76800
2	7000	9600	1547200	2080300	(533100)	1547200	8.00	76800
3	7000	9600	1547200	2045800	(498600)	1547200	8.00	76800
4	7000	9600	1547200	2011300	(464100)	1547200	8.00	76800
5	7000	9600	1547200	1976700	(429500)	1547200	8.00	76800
6	7000	9600	1547200	1942200	(395000)	1547200	8.00	76800
7	7000	9600	1547200	1907700	(360500)	1547200	8.00	76800
8	7000	9600	1547200	1873200	(326000)	1547200	8.00	76800
9	7000	9600	1547200	1838600	(291400)	1547200	8.00	76800
10	7000	9600	1547200	1804100	(256900)	1547200	8.00	76800
11	5000	6900	835700	1592500	(756800)	835700	5.00	34500
12	5000	6900	835700	1557900	(722200)	835700	5.00	34500
13	5000	6900	835700	1523400	(687700)	835700	5.00	34500
14	5000	6900	835700	1488900	(653200)	835700	5.00	34500
15	5000	6900	835700	1454400	(618700)	835700	5.00	34500
16	3500	4800	674800	1274200	(599400)	674800	5.00	24000
17	3500	4800	674800	1239700	(564900)	674800	5.00	24000
18	3500	4800	674800	1205200	(530400)	674800	5.00	24000
19	3500	4800	674800	1170600	(495800)	674800	5.00	24000
20	3500	4800	674800	1136100	(461300)	674800	5.00	24000
21	1500	2100	426800	874300	(447500)	426800	5.00	10500
22	1500	2100	426800	839800	(413000)	426800	5.00	10500
23	1500	2100	426800	805200	(378400)	426800	5.00	10500
24	1500	2100	426800	770700	(343900)	426800	5.00	10500
25	1500	2100	426800	736200	(309400)	426800	5.00	10500
26	1500	2100	426800	701600	(274800)	426800	5.00	10500
27	1500	2100	426800	667100	(240300)	426800	5.00	10500
28	1500	2100	426800	632600	(205800)	426800	5.00	10500
29	1500	2100	426800	598100	(171300)	426800	5.00	10500
30	1500	2100	426800	563500	(136700)	426800	5.00	10500
TOT	127500	175500	27292500	40426700	(13134200)	27292500		1165500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 6.5
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	644400	(1470400)	322200	(735200)	837000	(220400)	837000	(220400)	6.11	
2	609900	(1470400)	304950	(735200)	819750	(220400)	1656750	(440800)	5.78	
3	575400	(1470400)	287700	(735200)	802500	(220400)	2459250	(661200)	5.46	
4	540900	(1470400)	270450	(735200)	785250	(220400)	3244500	(881600)	5.13	
5	506300	(1470400)	253150	(735200)	767950	(220400)	4012450	(1102000)	4.80	
6	471800	(1470400)	235900	(735200)	750700	(220400)	4763150	(1322400)	4.47	
7	437300	(1470400)	218650	(735200)	733450	(220400)	5496600	(1542800)	4.15	
8	402800	(1470400)	201400	(735200)	716200	(220400)	6212800	(1763200)	3.82	
9	368200	(1470400)	184100	(735200)	698900	(220400)	6911700	(1983600)	3.49	
10	333700	(1470400)	166850	(735200)	681650	(220400)	7593350	(2204000)	3.16	
11	791300	(801200)	395650	(400600)	395650	(400600)	7989000	(2604600)	7.54	
12	756700	(801200)	378350	(400600)	378350	(400600)	8367350	(3005200)	7.21	
13	722200	(801200)	361100	(400600)	361100	(400600)	8728450	(3405800)	6.88	
14	687700	(801200)	343850	(400600)	343850	(400600)	9072300	(3806400)	6.55	
15	653200	(801200)	326600	(400600)	326600	(400600)	9398900	(4207000)	6.22	
16	623400	(650800)	311700	(325400)	311700	(325400)	9710600	(4532400)	5.97	
17	588900	(650800)	294450	(325400)	294450	(325400)	10005050	(4857800)	5.64	
18	554400	(650800)	277200	(325400)	277200	(325400)	10282250	(5183200)	5.30	
19	519800	(650800)	259900	(325400)	259900	(325400)	10542150	(5508600)	4.97	
20	485300	(650800)	242650	(325400)	242650	(325400)	10784800	(5834000)	4.64	
21	458000	(416300)	229000	(208150)	229000	(208150)	11013800	(6042150)	4.41	
22	423500	(416300)	211750	(208150)	211750	(208150)	11225550	(6250300)	4.08	
23	388900	(416300)	194450	(208150)	194450	(208150)	11420000	(6458450)	3.75	
24	354400	(416300)	177200	(208150)	177200	(208150)	11597200	(6666600)	3.41	
25	319900	(416300)	159950	(208150)	159950	(208150)	11757150	(6874750)	3.08	
26	285300	(416300)	142650	(208150)	142650	(208150)	11899800	(7082900)	2.75	
27	250800	(416300)	125400	(208150)	125400	(208150)	12025200	(7291050)	2.42	
28	216300	(416300)	108150	(208150)	108150	(208150)	12133350	(7499200)	2.08	
29	181800	(416300)	90900	(208150)	90900	(208150)	12224250	(7707350)	1.75	
30	147200	(416300)	73600	(208150)	73600	(208150)	12297850	(7915500)	1.42	
TOT	14299700	(26127000)	7149850	(13063500)	12297850	(7915500)			AVG= 4.99	

Table A-145

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 200 MW. NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 6690000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 8.0%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG%

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR		NET REVENUE, $/TON	TOTAL NET SALES REVENUE, $/YEAR
		100% H2SO4			WITH PAYMENT	WITHOUT PAYMENT	100% H2SO4	
1	7000	24100	2072500	2429700	(357200)	2072500	8.00	192800
2	7000	24100	2072500	2390200	(317700)	2072500	8.00	192800
3	7000	24100	2072500	2350700	(278200)	2072500	8.00	192800
4	7000	24100	2072500	2311100	(238600)	2072500	8.00	192800
5	7000	24100	2072500	2271600	(199100)	2072500	8.00	192800
6	7000	24100	2072500	2232100	(159600)	2072500	8.00	192800
7	7000	24100	2072500	2192600	(120100)	2072500	8.00	192800
8	7000	24100	2072500	2153100	(80600)	2072500	8.00	192800
9	7000	24100	2072500	2113500	(41000)	2072500	8.00	192800
10	7000	24100	2072500	2074000	(1500)	2072500	8.00	192800
11	5000	17200	1130100	1826600	(696500)	1130100	5.00	86000
12	5000	17200	1130100	1787100	(657000)	1130100	5.00	86000
13	5000	17200	1130100	1747600	(617500)	1130100	5.00	86000
14	5000	17200	1130100	1708000	(577900)	1130100	5.00	86000
15	5000	17200	1130100	1668500	(538400)	1130100	5.00	86000
16	3500	12000	908400	1459000	(550600)	908400	5.00	60000
17	3500	12000	908400	1419500	(511100)	908400	5.00	60000
18	3500	12000	908400	1380000	(471600)	908400	5.00	60000
19	3500	12000	908400	1340400	(432000)	908400	5.00	60000
20	3500	12000	908400	1300900	(392500)	908400	5.00	60000
21	1500	5200	568000	997500	(429500)	568000	5.00	26000
22	1500	5200	568000	958000	(390000)	568000	5.00	26000
23	1500	5200	568000	918500	(350500)	568000	5.00	26000
24	1500	5200	568000	878900	(310900)	568000	5.00	26000
25	1500	5200	568000	839400	(271400)	568000	5.00	26000
26	1500	5200	568000	799900	(231900)	568000	5.00	26000
27	1500	5200	568000	760400	(192400)	568000	5.00	26000
28	1500	5200	568000	720900	(152900)	568000	5.00	26000
29	1500	5200	568000	681300	(113300)	568000	5.00	26000
30	1500	5200	568000	641800	(73800)	568000	5.00	26000
TOT	127500	439000	36597500	46352800	(9755300)	36597500		2918000

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 7.6
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR		NET INCOME AFTER TAXES, $/YEAR		CASH FLOW, $/YEAR		CUMULATIVE CASH FLOW, $		ANNUAL RETURN ON INITIAL INVESTMENT, %	
	WITH PAYMENT	WITHOUT PAYMENT	WITH PAYMENT	WITHOUT PAYMENT	WITH PAYMENT	WITHOUT PAYMENT	WITH PAYMENT	WITHOUT PAYMENT	WITH PAYMENT	WITHOUT PAYMENT
1	550000	(1879700)	275000	(939850)	944000	(270850)	944000	(270850)	4.01	
2	510500	(1879700)	255250	(939850)	924250	(270850)	1868250	(541700)	3.72	
3	471000	(1879700)	235500	(939850)	904500	(270850)	2772750	(812550)	3.43	
4	431400	(1879700)	215700	(939850)	884700	(270850)	3657450	(1083400)	3.14	
5	391900	(1879700)	195950	(939850)	864950	(270850)	4522400	(1354250)	2.86	
6	352400	(1879700)	176200	(939850)	845200	(270850)	5367600	(1625100)	2.57	
7	312900	(1879700)	156450	(939850)	825450	(270850)	6193050	(1895950)	2.28	
8	273400	(1879700)	136700	(939850)	805700	(270850)	6998750	(2166800)	1.99	
9	233800	(1879700)	116900	(939850)	785900	(270850)	7784650	(2437650)	1.70	
10	194300	(1879700)	97150	(939850)	766150	(270850)	8550800	(2708500)	1.42	
11	782500	(1044100)	391250	(522050)	391250	(522050)	8942050	(3230550)	5.73	
12	743000	(1044100)	371500	(522050)	371500	(522050)	9313550	(3752600)	5.44	
13	703500	(1044100)	351750	(522050)	351750	(522050)	9665300	(4274650)	5.15	
14	663900	(1044100)	331950	(522050)	331950	(522050)	9997250	(4796700)	4.86	
15	624400	(1044100)	312200	(522050)	312200	(522050)	10309450	(5318750)	4.57	
16	610600	(848400)	305300	(424200)	305300	(424200)	10614750	(5742950)	4.49	
17	571100	(848400)	285550	(424200)	285550	(424200)	10900300	(6167150)	4.20	
18	531600	(848400)	265800	(424200)	265800	(424200)	11166100	(6591350)	3.91	
19	492000	(848400)	246000	(424200)	246000	(424200)	11412100	(7015550)	3.62	
20	452500	(848400)	226250	(424200)	226250	(424200)	11638350	(7439750)	3.33	
21	455500	(542000)	227750	(271000)	227750	(271000)	11866100	(7710750)	3.37	
22	416000	(542000)	208000	(271000)	208000	(271000)	12074100	(7981750)	3.08	
23	376500	(542000)	188250	(271000)	188250	(271000)	12262350	(8252750)	2.79	
24	336900	(542000)	168450	(271000)	168450	(271000)	12430800	(8523750)	2.50	
25	297400	(542000)	148700	(271000)	148700	(271000)	12579500	(8794750)	2.20	
26	257900	(542000)	128950	(271000)	128950	(271000)	12708450	(9065750)	1.91	
27	218400	(542000)	109200	(271000)	109200	(271000)	12817650	(9336750)	1.62	
28	178900	(542000)	89450	(271000)	89450	(271000)	12907100	(9607750)	1.33	
29	139300	(542000)	69650	(271000)	69650	(271000)	12976750	(9878750)	1.03	
30	99800	(542000)	49900	(271000)	49900	(271000)	13026650	(10149750)	0.75	
TOT	12673900	(33679500)	6336650	(16839750)	13026650	(10149750)			AVG= 3.13	

Table A-146

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 200 MW. NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 6690000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 9.9%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	24100	2072500	2514300	(441800)	2072500	8.00	192800
2	7000	24100	2072500	2483200	(410700)	2072500	8.00	192800
3	7000	24100	2072500	2452000	(379500)	2072500	8.00	192800
4	7000	24100	2072500	2420900	(348400)	2072500	8.00	192800
5	7000	24100	2072500	2389700	(317200)	2072500	8.00	192800
6	7000	24100	2072500	2358600	(286100)	2072500	8.00	192800
7	7000	24100	2072500	2327400	(254900)	2072500	8.00	192800
8	7000	24100	2072500	2296200	(223700)	2072500	8.00	192800
9	7000	24100	2072500	2265100	(192600)	2072500	8.00	192800
10	7000	24100	2072500	2233900	(161400)	2072500	8.00	192800
11	5000	17200	1130100	1875000	(744900)	1130100	5.00	86000
12	5000	17200	1130100	1843800	(713700)	1130100	5.00	86000
13	5000	17200	1130100	1812600	(682500)	1130100	5.00	86000
14	5000	17200	1130100	1781500	(651400)	1130100	5.00	86000
15	5000	17200	1130100	1750300	(620200)	1130100	5.00	86000
16	3500	12000	908400	1460900	(552500)	908400	5.00	60000
17	3500	12000	908400	1429700	(521300)	908400	5.00	60000
18	3500	12000	908400	1398600	(490200)	908400	5.00	60000
19	3500	12000	908400	1367400	(459000)	908400	5.00	60000
20	3500	12000	908400	1336200	(427800)	908400	5.00	60000
21	1500	5200	568000	927600	(359600)	568000	5.00	26000
22	1500	5200	568000	896400	(328400)	568000	5.00	26000
23	1500	5200	568000	865300	(297300)	568000	5.00	26000
24	1500	5200	568000	834100	(266100)	568000	5.00	26000
25	1500	5200	568000	802900	(234900)	568000	5.00	26000
26	1500	5200	568000	771800	(203800)	568000	5.00	26000
27	1500	5200	568000	740600	(172600)	568000	5.00	26000
28	1500	5200	568000	709500	(141500)	568000	5.00	26000
29	1500	5200	568000	678300	(110300)	568000	5.00	26000
30	1500	5200	568000	647200	(79200)	568000	5.00	26000
TOT	127500	439000	36597500	47671000	(11073500)	36597500		2918000

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 7.1
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	634600	(1879700)	317300	(939850)	986300	(270850)	986300	(270850)	4.62	
2	603500	(1879700)	301750	(939850)	970750	(270850)	1957050	(541700)	4.40	
3	572300	(1879700)	286150	(939850)	955150	(270850)	2912200	(812550)	4.17	
4	541200	(1879700)	270600	(939850)	939600	(270850)	3851800	(1083400)	3.94	
5	510000	(1879700)	255000	(939850)	924000	(270850)	4775800	(1354250)	3.72	
6	478900	(1879700)	239450	(939850)	908450	(270850)	5684250	(1625100)	3.49	
7	447700	(1879700)	223850	(939850)	892850	(270850)	6577100	(1895950)	3.26	
8	416500	(1879700)	208250	(939850)	877250	(270850)	7454350	(2166800)	3.03	
9	385400	(1879700)	192700	(939850)	861700	(270850)	8316050	(2437650)	2.81	
10	354200	(1879700)	177100	(939850)	846100	(270850)	9162150	(2708500)	2.58	
11	830900	(1044100)	415450	(522050)	415450	(522050)	9577600	(3230550)	6.09	
12	799700	(1044100)	399850	(522050)	399850	(522050)	9977450	(3752600)	5.86	
13	768500	(1044100)	384250	(522050)	384250	(522050)	10361700	(4274650)	5.63	
14	737400	(1044100)	368700	(522050)	368700	(522050)	10730400	(4796700)	5.40	
15	706200	(1044100)	353100	(522050)	353100	(522050)	11083500	(5318750)	5.17	
16	612500	(848400)	306250	(424200)	306250	(424200)	11389750	(5742950)	4.51	
17	581300	(848400)	290650	(424200)	290650	(424200)	11680400	(6167150)	4.28	
18	550200	(848400)	275100	(424200)	275100	(424200)	11955500	(6591350)	4.05	
19	519000	(848400)	259500	(424200)	259500	(424200)	12215000	(7015550)	3.82	
20	487800	(848400)	243900	(424200)	243900	(424200)	12458900	(7439750)	3.59	
21	385600	(542000)	192800	(271000)	192800	(271000)	12651700	(7710750)	2.86	
22	354400	(542000)	177200	(271000)	177200	(271000)	12828900	(7981750)	2.63	
23	323300	(542000)	161650	(271000)	161650	(271000)	12990550	(8252750)	2.40	
24	292100	(542000)	146050	(271000)	146050	(271000)	13136600	(8523750)	2.16	
25	260900	(542000)	130450	(271000)	130450	(271000)	13267050	(8794750)	1.93	
26	229800	(542000)	114900	(271000)	114900	(271000)	13381950	(9065750)	1.70	
27	198600	(542000)	99300	(271000)	99300	(271000)	13481250	(9336750)	1.47	
28	167500	(542000)	83750	(271000)	83750	(271000)	13565000	(9607750)	1.24	
29	136300	(542000)	68150	(271000)	68150	(271000)	13633150	(9878750)	1.01	
30	105200	(542000)	52600	(271000)	52600	(271000)	13685750	(10149750)	0.78	
TOT	13991500	(33679500)	6995750	(16839750)	13685750	(10149750)			AVG= 3.46	

Table A-147

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 200 MW. NEW OIL FIRED POWER PLANT, 4.0 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 7903000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 7.7%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	38500	2476100	2698700	(222600)	2476100	8.00	308000
2	7000	38500	2476100	2655100	(179000)	2476100	8.00	308000
3	7000	38500	2476100	2611500	(135400)	2476100	8.00	308000
4	7000	38500	2476100	2567900	(91800)	2476100	8.00	308000
5	7000	38500	2476100	2524300	(48200)	2476100	8.00	308000
6	7000	38500	2476100	2480700	(4600)	2476100	8.00	308000
7	7000	38500	2476100	2437100	39000	2476100	8.00	308000
8	7000	38500	2476100	2393500	82600	2476100	8.00	308000
9	7000	38500	2476100	2349900	126200	2476100	8.00	308000
10	7000	38500	2476100	2306300	169800	2476100	8.00	308000
11	5000	27500	1352300	2026300	(674000)	1352300	5.00	137500
12	5000	27500	1352300	1982700	(630400)	1352300	5.00	137500
13	5000	27500	1352300	1939100	(586800)	1352300	5.00	137500
14	5000	27500	1352300	1895500	(543200)	1352300	5.00	137500
15	5000	27500	1352300	1851900	(499600)	1352300	5.00	137500
16	3500	19300	1082300	1615800	(533500)	1082300	5.00	96500
17	3500	19300	1082300	1572200	(489900)	1082300	5.00	96500
18	3500	19300	1082300	1528600	(446300)	1082300	5.00	96500
19	3500	19300	1082300	1485000	(402700)	1082300	5.00	96500
20	3500	19300	1082300	1441400	(359100)	1082300	5.00	96500
21	1500	8300	671400	1100800	(429400)	671400	5.00	41500
22	1500	8300	671400	1057200	(385800)	671400	5.00	41500
23	1500	8300	671400	1013600	(342200)	671400	5.00	41500
24	1500	8300	671400	970000	(298600)	671400	5.00	41500
25	1500	8300	671400	926400	(255000)	671400	5.00	41500
26	1500	8300	671400	882800	(211400)	671400	5.00	41500
27	1500	8300	671400	839200	(167800)	671400	5.00	41500
28	1500	8300	671400	795600	(124200)	671400	5.00	41500
29	1500	8300	671400	752000	(80600)	671400	5.00	41500
30	1500	8300	671400	708400	(37000)	671400	5.00	41500
TOT	127500	702000	43648000	51409500	(7761500)	43648000		4665000

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 8.1
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	530600	(2168100)	265300	(1084050)	1055600	(293750)	1055600	(293750)	3.27	
2	487000	(2168100)	243500	(1084050)	1033800	(293750)	2089400	(587500)	3.00	
3	443400	(2168100)	221700	(1084050)	1012000	(293750)	3101400	(881250)	2.73	
4	399800	(2168100)	199900	(1084050)	990200	(293750)	4091600	(1175000)	2.46	
5	356200	(2168100)	178100	(1084050)	968400	(293750)	5060000	(1468750)	2.20	
6	312600	(2168100)	156300	(1084050)	946600	(293750)	6006600	(1762500)	1.93	
7	269000	(2168100)	134500	(1084050)	924800	(293750)	6931400	(2056250)	1.66	
8	225400	(2168100)	112700	(1084050)	903000	(293750)	7834400	(2350000)	1.39	
9	181800	(2168100)	90900	(1084050)	881200	(293750)	8715600	(2643750)	1.12	
10	138200	(2168100)	69100	(1084050)	859600	(293750)	9575000	(2937500)	0.85	
11	811500	(1214800)	405750	(607400)	405750	(607400)	9980750	(3544900)	5.03	
12	767900	(1214800)	383950	(607400)	383950	(607400)	10364700	(4152300)	4.76	
13	724300	(1214800)	362150	(607400)	362150	(607400)	10726850	(4759700)	4.49	
14	680700	(1214800)	340350	(607400)	340350	(607400)	11067200	(5367100)	4.22	
15	637100	(1214800)	318550	(607400)	318550	(607400)	11385750	(5974500)	3.95	
16	630000	(985800)	315000	(492900)	315000	(492900)	11700750	(6467400)	3.92	
17	586400	(985800)	293200	(492900)	293200	(492900)	11993950	(6960300)	3.65	
18	542800	(985800)	271400	(492900)	271400	(492900)	12265350	(7453200)	3.38	
19	499200	(985800)	249600	(492900)	249600	(492900)	12514950	(7946100)	3.11	
20	455600	(985800)	227800	(492900)	227800	(492900)	12742750	(8439000)	2.84	
21	470900	(629900)	235450	(314950)	235450	(314950)	12978200	(8753950)	2.95	
22	427300	(629900)	213650	(314950)	213650	(314950)	13191850	(9068900)	2.68	
23	383700	(629900)	191850	(314950)	191850	(314950)	13383700	(9383850)	2.41	
24	340100	(629900)	170050	(314950)	170050	(314950)	13553750	(9698800)	2.13	
25	296500	(629900)	148250	(314950)	148250	(314950)	13702000	(10013750)	1.86	
26	252900	(629900)	126450	(314950)	126450	(314950)	13828450	(10328700)	1.59	
27	209300	(629900)	104650	(314950)	104650	(314950)	13933100	(10643650)	1.31	
28	165700	(629900)	82850	(314950)	82850	(314950)	14015950	(10958600)	1.04	
29	122100	(629900)	61050	(314950)	61050	(314950)	14077000	(11273550)	0.77	
30	78500	(629900)	39250	(314950)	39250	(314950)	14116250	(11588500)	0.49	
TOT	12426500	(38983000)	6213250	(19491500)	14116250	(11588500)			AVG= 2.60	

Table A-148

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 200 MW, EXISTING OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 7426000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 8.8%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1								
2								
3								
4								
5								
6								
7								
8								
9	7000	24900	2241000	2794100	(553100)	2241000	8.00	199200
10	7000	24900	2241000	2732100	(491100)	2241000	8.00	199200
11	5000	17800	1951500	2443900	(492400)	1951500	8.00	142400
12	5000	17800	1951500	2381800	(430300)	1951500	8.00	142400
13	5000	17800	1951500	2319800	(368300)	1951500	8.00	142400
14	5000	17800	1951500	2257700	(306200)	1951500	8.00	142400
15	5000	17800	1951500	2195600	(244100)	1951500	8.00	142400
16	3500	12400	1716400	1947900	(231500)	1716400	8.00	99200
17	3500	12400	1716400	1885900	(169500)	1716400	8.00	99200
18	3500	12400	1716400	1823800	(107400)	1716400	8.00	99200
19	3500	12400	973800	1761700	(787900)	973800	5.00	62000
20	3500	12400	973800	1699700	(725900)	973800	5.00	62000
21	1500	5300	612100	1349200	(737100)	612100	5.00	26500
22	1500	5300	612100	1287100	(675000)	612100	5.00	26500
23	1500	5300	612100	1225100	(613000)	612100	5.00	26500
24	1500	5300	612100	1163000	(550900)	612100	5.00	26500
25	1500	5300	612100	1100900	(488800)	612100	5.00	26500
26	1500	5300	612100	1038900	(426800)	612100	5.00	26500
27	1500	5300	612100	976800	(364700)	612100	5.00	26500
28	1500	5300	612100	914700	(302600)	612100	5.00	26500
29	1500	5300	612100	852700	(240600)	612100	5.00	26500
30	1500	5300	612100	790600	(178500)	612100	5.00	26500
TOT	71500	253800	27457300	36943000	(9485700)	27457300		1797000

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 7.3
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1										
2										
3										
4										
5										
6										
7										
8										
9	752300	(2041800)	376150	(1020900)	1118750	(278300)	1118750	(278300)	4.94	
10	690300	(2041800)	345150	(1020900)	1087750	(278300)	2206500	(556600)	4.54	
11	634800	(1809100)	317400	(904550)	1060000	(161950)	3266500	(718550)	4.19	
12	572700	(1809100)	286350	(904550)	1028950	(161950)	4295450	(880500)	3.78	
13	510700	(1809100)	255350	(904550)	997950	(161950)	5293400	(1042450)	3.37	
14	448600	(1809100)	224300	(904550)	966900	(161950)	6260300	(1204400)	2.96	
15	386500	(1809100)	193250	(904550)	935850	(161950)	7196150	(1366350)	2.55	
16	330700	(1617200)	165350	(808600)	907950	(66000)	8104100	(1432350)	2.19	
17	268700	(1617200)	134350	(808600)	876950	(66000)	8981050	(1498350)	1.78	
18	206600	(1617200)	103300	(808600)	845900	(66000)	9826950	(1564350)	1.37	
19	849900	(911800)	424950	(455900)	424950	(455900)	10251900	(2020250)	5.64	
20	787900	(911800)	393950	(455900)	393950	(455900)	10645850	(2476150)	5.23	
21	763600	(585600)	381800	(292800)	381800	(292800)	11027650	(2768950)	5.10	
22	701500	(585600)	350750	(292800)	350750	(292800)	11378400	(3061750)	4.68	
23	639500	(585600)	319750	(292800)	319750	(292800)	11698150	(3354550)	4.27	
24	577400	(585600)	288700	(292800)	288700	(292800)	11986850	(3647350)	3.86	
25	515300	(585600)	257650	(292800)	257650	(292800)	12244500	(3940150)	3.44	
26	453300	(585600)	226650	(292800)	226650	(292800)	12471150	(4232950)	3.03	
27	391200	(585600)	195600	(292800)	195600	(292800)	12666750	(4525750)	2.61	
28	329100	(585600)	164550	(292800)	164550	(292800)	12831300	(4818550)	2.20	
29	267100	(585600)	133550	(292800)	133550	(292800)	12964850	(5111350)	1.78	
30	205000	(585600)	102500	(292800)	102500	(292800)	13067350	(5404150)	1.37	
TOT	11282700	(25660300)	5641350	(12830150)	13067350	(5404150)			AVG= 3.42	

Table A-149

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 500 MW. NEW OIL FIRED POWER PLANT, 1.0 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 9888000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 11.5%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	23600	2875200	3886100	(1010900)	2875200	8.00	188800
2	7000	23600	2875200	3820300	(945100)	2875200	8.00	188800
3	7000	23600	2875200	3754500	(879300)	2875200	8.00	188800
4	7000	23600	2875200	3688700	(813500)	2875200	8.00	188800
5	7000	23600	2875200	3622900	(747700)	2875200	8.00	188800
6	7000	23600	2875200	3557100	(681900)	2875200	8.00	188800
7	7000	23600	2875200	3491300	(616100)	2875200	8.00	188800
8	7000	23600	2875200	3425400	(550200)	2875200	8.00	188800
9	7000	23600	2875200	3359600	(484400)	2875200	8.00	188800
10	7000	23600	2875200	3293800	(418600)	2875200	8.00	188800
11	5000	16800	1511900	2903800	(1391900)	1511900	5.00	84000
12	5000	16800	1511900	2838000	(1326100)	1511900	5.00	84000
13	5000	16800	1511900	2772200	(1260300)	1511900	5.00	84000
14	5000	16800	1511900	2706400	(1194500)	1511900	5.00	84000
15	5000	16800	1511900	2640600	(1128700)	1511900	5.00	84000
16	3500	11800	1210500	2312200	(1101700)	1210500	5.00	59000
17	3500	11800	1210500	2246300	(1035800)	1210500	5.00	59000
18	3500	11800	1210500	2180500	(970000)	1210500	5.00	59000
19	3500	11800	1210500	2114700	(904200)	1210500	5.00	59000
20	3500	11800	1210500	2048900	(838400)	1210500	5.00	59000
21	1500	5000	754600	1583000	(828400)	754600	5.00	25000
22	1500	5000	754600	1517200	(762600)	754600	5.00	25000
23	1500	5000	754600	1451400	(696800)	754600	5.00	25000
24	1500	5000	754600	1385600	(631000)	754600	5.00	25000
25	1500	5000	754600	1319800	(565200)	754600	5.00	25000
26	1500	5000	754600	1253900	(499300)	754600	5.00	25000
27	1500	5000	754600	1188100	(433500)	754600	5.00	25000
28	1500	5000	754600	1122300	(367700)	754600	5.00	25000
29	1500	5000	754600	1056500	(301900)	754600	5.00	25000
30	1500	5000	754600	990700	(236100)	754600	5.00	25000
TOT	127500	429000	49910000	73531800	(23621800)	49910000		2853000

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 6.6
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	1199700	(2686400)	599850	(1343200)	1588650	(354400)	1588650	(354400)	5.93	
2	1133900	(2686400)	566950	(1343200)	1555750	(354400)	3144400	(708800)	5.60	
3	1068100	(2686400)	534050	(1343200)	1522850	(354400)	4667250	(1063200)	5.28	
4	1002300	(2686400)	501150	(1343200)	1489950	(354400)	6157200	(1417600)	4.95	
5	936500	(2686400)	468250	(1343200)	1457050	(354400)	7614250	(1772000)	4.63	
6	870700	(2686400)	435350	(1343200)	1424150	(354400)	9038400	(2126400)	4.30	
7	804900	(2686400)	402450	(1343200)	1391250	(354400)	10429650	(2480800)	3.98	
8	739000	(2686400)	369500	(1343200)	1358300	(354400)	11787950	(2835200)	3.65	
9	673200	(2686400)	336600	(1343200)	1325400	(354400)	13113350	(3189600)	3.33	
10	607400	(2686400)	303700	(1343200)	1292500	(354400)	14405850	(3544000)	3.00	
11	1475900	(1427900)	737950	(713950)	737950	(713950)	15143800	(4257950)	7.33	
12	1410100	(1427900)	705050	(713950)	705050	(713950)	15848850	(4971900)	7.00	
13	1344300	(1427900)	672150	(713950)	672150	(713950)	16521000	(5685850)	6.68	
14	1278500	(1427900)	639250	(713950)	639250	(713950)	17160250	(6399800)	6.35	
15	1212700	(1427900)	606350	(713950)	606350	(713950)	17766600	(7113750)	6.02	
16	1160700	(1151500)	580350	(575750)	580350	(575750)	18346950	(7689500)	5.79	
17	1094800	(1151500)	547400	(575750)	547400	(575750)	18894350	(8265250)	5.46	
18	1029000	(1151500)	514500	(575750)	514500	(575750)	19408850	(8841000)	5.13	
19	963200	(1151500)	481600	(575750)	481600	(575750)	19890450	(9416750)	4.80	
20	897400	(1151500)	448700	(575750)	448700	(575750)	20339150	(9992500)	4.48	
21	853400	(729600)	426700	(364800)	426700	(364800)	20765850	(10357300)	4.28	
22	787600	(729600)	393800	(364800)	393800	(364800)	21159650	(10722100)	3.95	
23	721800	(729600)	360900	(364800)	360900	(364800)	21520550	(11086900)	3.62	
24	656000	(729600)	328000	(364800)	328000	(364800)	21848550	(11451700)	3.29	
25	590200	(729600)	295100	(364800)	295100	(364800)	22143650	(11816500)	2.96	
26	524300	(729600)	262150	(364800)	262150	(364800)	22405800	(12181300)	2.63	
27	458500	(729600)	229250	(364800)	229250	(364800)	22635050	(12546100)	2.30	
28	392700	(729600)	196350	(364800)	196350	(364800)	22831400	(12910900)	1.97	
29	326900	(729600)	163450	(364800)	163450	(364800)	22994850	(13275700)	1.64	
30	261100	(729600)	130550	(364800)	130550	(364800)	23125400	(13640500)	1.31	
TOT	26474800	(47057000)	13237400	(23528500)	23125400	(13640500)			AVG= 4.43	

Table A-150

MAGNESIA SCHEME A. NONREGULATED CO. ECONOMICS, 500 MW. NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 12439000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 9.8%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR		NET REVENUE, $/TON	TOTAL NET SALES REVENUE, $/YEAR
		100% H2SO4			WITH PAYMENT	WITHOUT PAYMENT	100% H2SO4	
1	7000	58900	3730800	4454500 (	723700)	3730800	8.00	471200
2	7000	58900	3730800	4380500 (	649700)	3730800	8.00	471200
3	7000	58900	3730800	4306400 (	575600)	3730800	8.00	471200
4	7000	58900	3730800	4232400 (	501600)	3730800	8.00	471200
5	7000	58900	3730800	4158300 (	427500)	3730800	8.00	471200
6	7000	58900	3730800	4084300 (	353500)	3730800	8.00	471200
7	7000	58900	3730800	4010200 (	279400)	3730800	8.00	471200
8	7000	58900	3730800	3936200 (	205400)	3730800	8.00	471200
9	7000	58900	3730800	3862100 (	131300)	3730800	8.00	471200
10	7000	58900	3730800	3788100 (	57300)	3730800	8.00	471200
11	5000	42100	1977200	3325700 (	1348500)	1977200	5.00	210500
12	5000	42100	1977200	3251600 (	1274400)	1977200	5.00	210500
13	5000	42100	1977200	3177600 (	1200400)	1977200	5.00	210500
14	5000	42100	1977200	3103500 (	1126300)	1977200	5.00	210500
15	5000	42100	1977200	3029500 (	1052300)	1977200	5.00	210500
16	3500	29400	1570400	2642700 (	1072300)	1570400	5.00	147000
17	3500	29400	1570400	2568700 (	998300)	1570400	5.00	147000
18	3500	29400	1570400	2494600 (	924200)	1570400	5.00	147000
19	3500	29400	1570400	2420600 (	850200)	1570400	5.00	147000
20	3500	29400	1570400	2346500 (	776100)	1570400	5.00	147000
21	1500	12600	962900	1798300 (	835400)	962900	5.00	63000
22	1500	12600	962900	1724200 (	761300)	962900	5.00	63000
23	1500	12600	962900	1650200 (	687300)	962900	5.00	63000
24	1500	12600	962900	1576100 (	613200)	962900	5.00	63000
25	1500	12600	962900	1502100 (	539200)	962900	5.00	63000
26	1500	12600	962900	1428000 (	465100)	962900	5.00	63000
27	1500	12600	962900	1354000 (	391100)	962900	5.00	63000
28	1500	12600	962900	1279900 (	317000)	962900	5.00	63000
29	1500	12600	962900	1205900 (	243000)	962900	5.00	63000
30	1500	12600	962900	1131800 (	168900)	962900	5.00	63000
TOT	127500	1072500	64675000	84224500 (	19549500)	64675000		7129500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 7.2
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR		NET INCOME AFTER TAXES, $/YEAR		CASH FLOW, $/YEAR		CUMULATIVE CASH FLOW, $		ANNUAL RETURN ON INITIAL INVESTMENT, %	
	WITH PAYMENT	WITHOUT PAYMENT	WITH PAYMENT	WITHOUT PAYMENT	WITH PAYMENT	WITHOUT PAYMENT	WITH PAYMENT	WITHOUT PAYMENT	WITH PAYMENT	WITHOUT PAYMENT
1	1194900	(3259600)	597450	(1629800)	1841350	(385900)	1841350	(385900)	4.69	
2	1120900	(3259600)	560450	(1629800)	1804350	(385900)	3645700	(771800)	4.40	
3	1046800	(3259600)	523400	(1629800)	1767300	(385900)	5413000	(1157700)	4.11	
4	972800	(3259600)	486400	(1629800)	1730300	(385900)	7143300	(1543600)	3.82	
5	898700	(3259600)	449350	(1629800)	1693250	(385900)	8836550	(1929500)	3.53	
6	824700	(3259600)	412350	(1629800)	1656250	(385900)	10492800	(2315400)	3.24	
7	750600	(3259600)	375300	(1629800)	1619200	(385900)	12112000	(2701300)	2.94	
8	676600	(3259500)	338300	(1629800)	1582200	(385900)	13694200	(3087200)	2.65	
9	602500	(3259600)	301250	(1629800)	1545150	(385900)	15239350	(3473100)	2.36	
10	528500	(3259600)	264250	(1629800)	1508150	(385900)	16747500	(3859000)	2.07	
11	1559000	(1766700)	779500	(883350)	779500	(883350)	17527000	(4742350)	6.15	
12	1484900	(1766700)	742450	(883350)	742450	(883350)	18269450	(5625700)	5.86	
13	1410900	(1766700)	705450	(883350)	705450	(883350)	18974900	(6509050)	5.57	
14	1336800	(1766700)	668400	(883350)	668400	(883350)	19643300	(7392400)	5.27	
15	1262800	(1766700)	631400	(883350)	631400	(883350)	20274700	(8275750)	4.98	
16	1219300	(1423400)	609650	(711700)	609650	(711700)	20884350	(8987450)	4.83	
17	1145300	(1423400)	572650	(711700)	572650	(711700)	21457000	(9699150)	4.54	
18	1071200	(1423400)	535600	(711700)	535600	(711700)	21992600	(10410850)	4.24	
19	997200	(1423400)	498600	(711700)	498600	(711700)	22491200	(11122550)	3.95	
20	923100	(1423400)	461550	(711700)	461550	(711700)	22952750	(11836250)	3.66	
21	898400	(899900)	449200	(449950)	449200	(449950)	23401950	(12284200)	3.58	
22	824300	(899900)	412150	(449950)	412150	(449950)	23814100	(12734150)	3.29	
23	750300	(899900)	375150	(449950)	375150	(449950)	24189250	(13184100)	2.99	
24	676200	(899900)	338100	(449950)	338100	(449950)	24527350	(13634050)	2.70	
25	602200	(899900)	301100	(449950)	301100	(449950)	24828450	(14084000)	2.40	
26	528100	(899900)	264050	(449950)	264050	(449950)	25092500	(14533950)	2.11	
27	454100	(899900)	227050	(449950)	227050	(449950)	25319550	(14983900)	1.81	
28	380000	(899900)	190000	(449950)	190000	(449950)	25509550	(15433850)	1.52	
29	306000	(899900)	153000	(449950)	153000	(449950)	25662550	(15883800)	1.22	
30	231900	(899900)	115950	(449950)	115950	(449950)	25778500	(16333750)	0.92	
TOT	26679000	(57545500)	13339500	(28772750)	25778500	(16333750)		AVG=	3.55	

Table A-151

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 500 MW, NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 12439000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 13.0%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	58900	3730800	5015800	(1285000)	3730800	8.00	471200
2	7000	58900	3730800	4955600	(1224800)	3730800	8.00	471200
3	7000	58900	3730800	4895400	(1164600)	3730800	8.00	471200
4	7000	58900	3730800	4835200	(1104400)	3730800	8.00	471200
5	7000	58900	3730800	4775000	(1044200)	3730800	8.00	471200
6	7000	58900	3730800	4714800	(984000)	3730800	8.00	471200
7	7000	58900	3730800	4654600	(923800)	3730800	8.00	471200
8	7000	58900	3730800	4594400	(863600)	3730800	8.00	471200
9	7000	58900	3730800	4534200	(803400)	3730800	8.00	471200
10	7000	58900	3730800	4474000	(743200)	3730800	8.00	471200
11	5000	42100	1977200	3712000	(1734800)	1977200	5.00	210500
12	5000	42100	1977200	3651800	(1674600)	1977200	5.00	210500
13	5000	42100	1977200	3591600	(1614400)	1977200	5.00	210500
14	5000	42100	1977200	3531400	(1554200)	1977200	5.00	210500
15	5000	42100	1977200	3471200	(1494000)	1977200	5.00	210500
16	3500	29400	1570400	2865100	(1294700)	1570400	5.00	147000
17	3500	29400	1570400	2804900	(1234500)	1570400	5.00	147000
18	3500	29400	1570400	2744700	(1174300)	1570400	5.00	147000
19	3500	29400	1570400	2684600	(1114200)	1570400	5.00	147000
20	3500	29400	1570400	2624400	(1054000)	1570400	5.00	147000
21	1500	12600	962900	1783400	(820500)	962900	5.00	63000
22	1500	12600	962900	1723200	(760300)	962900	5.00	63000
23	1500	12600	962900	1663000	(700100)	962900	5.00	63000
24	1500	12600	962900	1602800	(639900)	962900	5.00	63000
25	1500	12600	962900	1542600	(579700)	962900	5.00	63000
26	1500	12600	962900	1482400	(519500)	962900	5.00	63000
27	1500	12600	962900	1422200	(459300)	962900	5.00	63000
28	1500	12600	962900	1362000	(399100)	962900	5.00	63000
29	1500	12600	962900	1301800	(338900)	962900	5.00	63000
30	1500	12600	962900	1241600	(278700)	962900	5.00	63000
TOT	127500	1072500	64675300	94255700	(29580700)	64675000		7129500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 6.1
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	1756200	(3259600)	878100	(1629800)	2122000	(385900)	2122000	(385900)	6.89	
2	1696000	(3259600)	848000	(1629800)	2091900	(385900)	4213900	(771800)	6.65	
3	1635800	(3259600)	817900	(1629800)	2061800	(385900)	6275700	(1157700)	6.42	
4	1575600	(3259600)	787800	(1629800)	2031700	(385900)	8307400	(1543600)	6.18	
5	1515400	(3259600)	757700	(1629800)	2001600	(385900)	10309000	(1929500)	5.95	
6	1455200	(3259600)	727600	(1629800)	1971500	(385900)	12280500	(2315400)	5.71	
7	1395000	(3259600)	697500	(1629800)	1941400	(385900)	14221900	(2701300)	5.47	
8	1334800	(3259600)	667400	(1629800)	1911300	(385900)	16133200	(3087200)	5.24	
9	1274600	(3259600)	637300	(1629800)	1881200	(385900)	18014400	(3473100)	5.00	
10	1214400	(3259600)	607200	(1629800)	1851100	(385900)	19865500	(3859000)	4.76	
11	1945300	(1766700)	972650	(883350)	972650	(883350)	20838150	(4742350)	7.67	
12	1885100	(1766700)	942550	(883350)	942550	(883350)	21780700	(5625700)	7.44	
13	1824900	(1766700)	912450	(883350)	912450	(883350)	22693150	(6509050)	7.20	
14	1764700	(1766700)	882350	(883350)	882350	(883350)	23575500	(7392400)	6.96	
15	1704500	(1766700)	852250	(883350)	852250	(883350)	24427750	(8275750)	6.72	
16	1441700	(1423400)	720850	(711700)	720850	(711700)	25148600	(8987450)	5.71	
17	1381500	(1423400)	690750	(711700)	690750	(711700)	25839350	(9699150)	5.47	
18	1321300	(1423400)	660650	(711700)	660650	(711700)	26500000	(10410850)	5.24	
19	1261200	(1423400)	630600	(711700)	630600	(711700)	27130600	(11122550)	5.00	
20	1201000	(1423400)	600500	(711700)	600500	(711700)	27731100	(11834250)	4.76	
21	883500	(899900)	441750	(449950)	441750	(449950)	28172850	(12284200)	3.52	
22	823300	(899900)	411650	(449950)	411650	(449950)	28584500	(12734150)	3.28	
23	763100	(899900)	381550	(449950)	381550	(449950)	28966050	(13184100)	3.04	
24	702900	(899900)	351450	(449950)	351450	(449950)	29317500	(13634050)	2.80	
25	642700	(899900)	321350	(449950)	321350	(449950)	29638850	(14084000)	2.56	
26	582500	(899900)	291250	(449950)	291250	(449950)	29930100	(14533950)	2.32	
27	522300	(899900)	261150	(449950)	261150	(449950)	30191250	(14983900)	2.08	
28	462100	(899900)	231050	(449950)	231050	(449950)	30422300	(15433850)	1.84	
29	401900	(899900)	200950	(449950)	200950	(449950)	30623250	(15883800)	1.60	
30	341700	(899900)	170850	(449950)	170850	(449950)	30794100	(16333750)	1.36	
TOT	36710200	(57545500)	18355100	(28772750)	30794100	(16333750)			AVG= 4.88	

Table A-152

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 500 MW. NEW OIL FIRED POWER PLANT, 4.0 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 14560000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 9.0%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	94200	4469000	4964100	(495100)	4469000	8.00	753600
2	7000	94200	4469000	4883000	(414000)	4469000	8.00	753600
3	7000	94200	4469000	4801900	(332900)	4469000	8.00	753600
4	7000	94200	4469000	4720800	(251800)	4469000	8.00	753600
5	7000	94200	4469000	4639700	(170700)	4469000	8.00	753600
6	7000	94200	4469000	4558600	(89600)	4469000	8.00	753600
7	7000	94200	4469000	4477500	(8500)	4469000	8.00	753600
8	7000	94200	4469000	4396400	72600	4469000	8.00	753600
9	7000	94200	4469000	4315300	153700	4469000	8.00	753600
10	7000	94200	4469000	4234200	234800	4469000	8.00	753600
11	5000	67300	2383400	3703700	(1320300)	2383400	5.00	336500
12	5000	67300	2383400	3622600	(1239200)	2383400	5.00	336500
13	5000	67300	2383400	3541500	(1158100)	2383400	5.00	336500
14	5000	67300	2383400	3460400	(1077000)	2383400	5.00	336500
15	5000	67300	2383400	3379300	(995900)	2383400	5.00	336500
16	3500	47100	1883700	2937400	(1053700)	1883700	5.00	235500
17	3500	47100	1883700	2856300	(972600)	1883700	5.00	235500
18	3500	47100	1883700	2775200	(891500)	1883700	5.00	235500
19	3500	47100	1883700	2694100	(810400)	1883700	5.00	235500
20	3500	47100	1883700	2613000	(729300)	1883700	5.00	235500
21	1500	20200	1142500	1988500	(846000)	1142500	5.00	101000
22	1500	20200	1142500	1907400	(764900)	1142500	5.00	101000
23	1500	20200	1142500	1826300	(683800)	1142500	5.00	101000
24	1500	20200	1142500	1745200	(602700)	1142500	5.00	101000
25	1500	20200	1142500	1664100	(521600)	1142500	5.00	101000
26	1500	20200	1142500	1583000	(440500)	1142500	5.00	101000
27	1500	20200	1142500	1501900	(359400)	1142500	5.00	101000
28	1500	20200	1142500	1420800	(278300)	1142500	5.00	101000
29	1500	20200	1142500	1339700	(197200)	1142500	5.00	101000
30	1500	20200	1142500	1258600	(116100)	1142500	5.00	101000
TOT	127500	1716000	77450500	93810500	(16360000)	77450500		11406000

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 7.5
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	1248700	(3715400)	624350	(1857700)	2081150	(400900)	2081150	(400900)	4.18	
2	1167600	(3715400)	583800	(1857700)	2040600	(400900)	4121750	(801800)	3.91	
3	1086500	(3715400)	543250	(1857700)	2000050	(400900)	6121800	(1202700)	3.64	
4	1005400	(3715400)	502700	(1857700)	1959500	(400900)	8081300	(1603600)	3.36	
5	924300	(3715400)	462150	(1857700)	1918950	(400900)	10000250	(2004500)	3.09	
6	843200	(3715400)	421600	(1857700)	1878400	(400900)	11878650	(2405400)	2.82	
7	762100	(3715400)	381050	(1857700)	1837850	(400900)	13716500	(2806300)	2.55	
8	681000	(3715400)	340500	(1857700)	1797300	(400900)	15513800	(3207200)	2.28	
9	599900	(3715400)	299950	(1857700)	1756750	(400900)	17270550	(3608100)	2.01	
10	518800	(3715400)	259400	(1857700)	1716200	(400900)	18986750	(4009000)	1.74	
11	1656800	(2046900)	828400	(1023450)	828400	(1023450)	19815150	(5032450)	5.58	
12	1575700	(2046900)	787850	(1023450)	787850	(1023450)	20603000	(6055900)	5.30	
13	1494600	(2046900)	747300	(1023450)	747300	(1023450)	21350300	(7079350)	5.03	
14	1413500	(2046900)	706750	(1023450)	706750	(1023450)	22057050	(8102800)	4.76	
15	1332400	(2046900)	666200	(1023450)	666200	(1023450)	22723250	(9126250)	4.48	
16	1289200	(1648200)	644600	(824100)	644600	(824100)	23367850	(9950350)	4.36	
17	1208100	(1648200)	604050	(824100)	604050	(824100)	23971900	(10774450)	4.09	
18	1127000	(1648200)	563500	(824100)	563500	(824100)	24535400	(11598550)	3.81	
19	1045900	(1648200)	522950	(824100)	522950	(824100)	25058350	(12422650)	3.54	
20	964800	(1648200)	482400	(824100)	482400	(824100)	25540750	(13246750)	3.26	
21	947000	(1041500)	473500	(520750)	473500	(520750)	26014250	(13767500)	3.22	
22	865900	(1041500)	432950	(520750)	432950	(520750)	26447200	(14288250)	2.95	
23	784800	(1041500)	392400	(520750)	392400	(520750)	26839600	(14809000)	2.67	
24	703700	(1041500)	351850	(520750)	351850	(520750)	27191450	(15329750)	2.40	
25	622600	(1041500)	311300	(520750)	311300	(520750)	27502750	(15850500)	2.12	
26	541500	(1041500)	270750	(520750)	270750	(520750)	27773500	(16371250)	1.84	
27	460400	(1041500)	230200	(520750)	230200	(520750)	28003700	(16892000)	1.57	
28	379300	(1041500)	189650	(520750)	189650	(520750)	28193350	(17412750)	1.29	
29	298200	(1041500)	149100	(520750)	149100	(520750)	28342450	(17933500)	1.02	
30	217100	(1041500)	108550	(520750)	108550	(520750)	28451000	(18454250)	0.74	
TOT	27766000	(66044500)	13883000	(33022250)	28451000	(18454250)			AVG= 3.15	

Table A-153

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 500 MW, EXISTING OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 13920000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 10.0%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1								
2								
3								
4	7000	60200	4044800	5032800	(988000)	4044800	8.00	481600
5	7000	60200	4044800	4938200	(893400)	4044800	8.00	481600
6	7000	60200	4044800	4843600	(798800)	4044800	8.00	481600
7	7000	60200	4044800	4749000	(704200)	4044800	8.00	481600
8	7000	60200	4044800	4654400	(609600)	4044800	8.00	481600
9	7000	60200	4044800	4559800	(515000)	4044800	8.00	481600
10	7000	60200	4044800	4465100	(420300)	4044800	8.00	481600
11	5000	43000	3508100	3953400	(445300)	3508100	8.00	344000
12	5000	43000	3508100	3858800	(350700)	3508100	8.00	344000
13	5000	43000	3508100	3764200	(256100)	3508100	8.00	344000
14	5000	43000	2116100	3669600	(1553500)	2116100	5.00	215000
15	5000	43000	2116100	3574900	(1458800)	2116100	5.00	215000
16	3500	30100	1686400	3143500	(1457100)	1686400	5.00	150500
17	3500	30100	1686400	3048900	(1362500)	1686400	5.00	150500
18	3500	30100	1686400	2954300	(1267900)	1686400	5.00	150500
19	3500	30100	1686400	2859700	(1173300)	1686400	5.00	150500
20	3500	30100	1686400	2765000	(1078600)	1686400	5.00	150500
21	1500	12900	1042600	2157000	(1114400)	1042600	5.00	64500
22	1500	12900	1042600	2062400	(1019800)	1042600	5.00	64500
23	1500	12900	1042600	1967800	(925200)	1042600	5.00	64500
24	1500	12900	1042600	1873200	(830600)	1042600	5.00	64500
25	1500	12900	1042600	1778500	(735900)	1042600	5.00	64500
26	1500	12900	1042600	1683900	(641300)	1042600	5.00	64500
27	1500	12900	1042600	1589300	(546700)	1042600	5.00	64500
28	1500	12900	1042600	1494700	(452100)	1042600	5.00	64500
29	1500	12900	1042600	1400100	(357500)	1042600	5.00	64500
30	1500	12900	1042600	1305400	(262800)	1042600	5.00	64500
TOT	106500	915900	61928100	84147500	(22219400)	61928100		6230700

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 7.0
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1										
2										
3										
4	1469600	(3563200)	734800	(1781600)	2126800	(389600)	2126800	(389600)	5.15	
5	1375000	(3563200)	687500	(1781600)	2079500	(389600)	4206300	(779200)	4.83	
6	1280400	(3563200)	640200	(1781600)	2032200	(389600)	6238500	(1168800)	4.49	
7	1185800	(3563200)	592900	(1781600)	1984900	(389600)	8223400	(1558400)	4.16	
8	1091200	(3563200)	545600	(1781600)	1937600	(389600)	10161000	(1948000)	3.83	
9	996600	(3563200)	498300	(1781600)	1890300	(389600)	12051300	(2337600)	3.50	
10	901900	(3563200)	450950	(1781600)	1842950	(389600)	13894250	(2727200)	3.17	
11	789300	(3164100)	394650	(1582050)	1786650	(190050)	15680900	(2917250)	2.79	
12	694700	(3164100)	347350	(1582050)	1739350	(190050)	17420250	(3107300)	2.45	
13	600100	(3164100)	300050	(1582050)	1692050	(190050)	19112300	(3297350)	2.12	
14	1768500	(1901100)	884250	(950550)	884250	(950550)	19996550	(4247900)	6.24	
15	1673880	(1901100)	836940	(950550)	836940	(950550)	20833490	(5198450)	5.91	
16	1607600	(1535900)	803800	(767950)	803800	(767950)	21637290	(5966400)	5.70	
17	1513000	(1535900)	756500	(767950)	756500	(767950)	22393790	(6734350)	5.36	
18	1418400	(1535900)	709200	(767950)	709200	(767950)	23102990	(7502300)	5.03	
19	1323800	(1535900)	661900	(767950)	661900	(767950)	23764890	(8270250)	4.69	
20	1229020	(1535900)	614510	(767950)	614510	(767950)	24379400	(9038200)	4.35	
21	1178900	(978100)	589450	(489050)	589450	(489050)	24968850	(9527250)	4.20	
22	1084300	(978100)	542150	(489050)	542150	(489050)	25511000	(10016300)	3.87	
23	989700	(978100)	494850	(489050)	494850	(489050)	26005850	(10505350)	3.53	
24	895100	(978100)	447550	(489050)	447550	(489050)	26453400	(10994400)	3.19	
25	800400	(978100)	400200	(489050)	400200	(489050)	26853600	(11483450)	2.85	
26	705800	(978100)	352900	(489050)	352900	(489050)	27206500	(11972500)	2.52	
27	611200	(978100)	305600	(489050)	305600	(489050)	27512100	(12461550)	2.18	
28	516600	(978100)	258300	(489050)	258300	(489050)	27770400	(12950600)	1.84	
29	422000	(978100)	211000	(489050)	211000	(489050)	27981400	(13439650)	1.50	
30	327300	(978100)	163650	(489050)	163650	(489050)	28145050	(13928700)	1.17	
TOT	28450100	(55697400)	14225050	(27848700)	28145050	(13928700)			AVG= 3.76	

Table A-154

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 1000 MW, NEW OIL FIRED POWER PLANT, 1.0 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 14957000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 12.4%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	45500	4306000	5979600	(1673600)	4306000	8.00	364000
2	7000	45500	4306000	5877300	(1571300)	4306000	8.00	364000
3	7000	45500	4306000	5774900	(1468900)	4306000	8.00	364000
4	7000	45500	4306000	5672500	(1366500)	4306000	8.00	364000
5	7000	45500	4306000	5570100	(1264100)	4306000	8.00	364000
6	7000	45500	4306000	5467700	(1161700)	4306000	8.00	364000
7	7000	45500	4306000	5365400	(1059400)	4306000	8.00	364000
8	7000	45500	4306000	5263000	(957000)	4306000	8.00	364000
9	7000	45500	4306000	5160600	(854600)	4306000	8.00	364000
10	7000	45500	4306000	5058200	(752200)	4306000	8.00	364000
11	5000	32500	2227600	4448600	(2221000)	2227600	5.00	162500
12	5000	32500	2227600	4346200	(2118600)	2227600	5.00	162500
13	5000	32500	2227600	4243800	(2016200)	2227600	5.00	162500
14	5000	32500	2227600	4141400	(1913800)	2227600	5.00	162500
15	5000	32500	2227600	4039000	(1811400)	2227600	5.00	162500
16	3500	22800	1765100	3530500	(1765400)	1765100	5.00	114000
17	3500	22800	1765100	3428100	(1663000)	1765100	5.00	114000
18	3500	22800	1765100	3325700	(1560600)	1765100	5.00	114000
19	3500	22800	1765100	3223300	(1458200)	1765100	5.00	114000
20	3500	22800	1765100	3121000	(1355900)	1765100	5.00	114000
21	1500	9800	1080900	2409700	(1328800)	1080900	5.00	49000
22	1500	9800	1080900	2307300	(1226400)	1080900	5.00	49000
23	1500	9800	1080900	2204900	(1124000)	1080900	5.00	49000
24	1500	9800	1080900	2102500	(1021600)	1080900	5.00	49000
25	1500	9800	1080900	2000200	(919300)	1080900	5.00	49000
26	1500	9800	1080900	1897800	(816900)	1080900	5.00	49000
27	1500	9800	1080900	1795400	(714500)	1080900	5.00	49000
28	1500	9800	1080900	1693000	(612100)	1080900	5.00	49000
29	1500	9800	1080900	1590700	(509800)	1080900	5.00	49000
30	1500	9800	1080900	1488300	(407400)	1080900	5.00	49000
TOT	127500	929500	73832500	112526700	(38694200)	73832500		5512500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 6.3
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	2037600	(3942000)	1018800	(1971000)	2514500	(475300)	2514500	(475300)	6.66	
2	1935300	(3942000)	967650	(1971000)	2463350	(475300)	4977850	(950600)	6.33	
3	1832900	(3942000)	916450	(1971000)	2412150	(475300)	7390000	(1425900)	5.99	
4	1730500	(3942000)	865250	(1971000)	2360950	(475300)	9750950	(1901200)	5.66	
5	1628100	(3942000)	814050	(1971000)	2309750	(475300)	12060700	(2376500)	5.32	
6	1525700	(3942000)	762850	(1971000)	2258550	(475300)	14319250	(2851800)	4.99	
7	1423400	(3942000)	711700	(1971000)	2207400	(475300)	16526650	(3327100)	4.65	
8	1321000	(3942000)	660500	(1971000)	2156200	(475300)	18682850	(3802400)	4.32	
9	1218600	(3942000)	609300	(1971000)	2105000	(475300)	20787850	(4277700)	3.98	
10	1116200	(3942000)	558100	(1971000)	2053800	(475300)	22841650	(4753000)	3.65	
11	2383500	(2065100)	1191750	(1032550)	1191750	(1032550)	24033400	(5785550)	7.83	
12	2281100	(2065100)	1140550	(1032550)	1140550	(1032550)	25173950	(6818100)	7.49	
13	2178700	(2065100)	1089350	(1032550)	1089350	(1032550)	26263300	(7850650)	7.16	
14	2076300	(2065100)	1038150	(1032550)	1038150	(1032550)	27301450	(8883200)	6.82	
15	1973900	(2065100)	986950	(1032550)	986950	(1032550)	28288400	(9915750)	6.49	
16	1879400	(1651100)	939700	(825550)	939700	(825550)	29228100	(10741300)	6.20	
17	1777000	(1651100)	888500	(825550)	888500	(825550)	30116600	(11566850)	5.86	
18	1674600	(1651100)	837300	(825550)	837300	(825550)	30953900	(12392400)	5.52	
19	1572200	(1651100)	786100	(825550)	786100	(825550)	31740000	(13217950)	5.19	
20	1469900	(1651100)	734950	(825550)	734950	(825550)	32474950	(14043500)	4.85	
21	1377800	(1031900)	688900	(515950)	688900	(515950)	33163850	(14559450)	4.57	
22	1275400	(1031900)	637700	(515950)	637700	(515950)	33801550	(15075400)	4.23	
23	1173000	(1031900)	586500	(515950)	586500	(515950)	34388050	(15591350)	3.89	
24	1070600	(1031900)	535300	(515950)	535300	(515950)	34923350	(16107300)	3.55	
25	968300	(1031900)	484150	(515950)	484150	(515950)	35407500	(16623250)	3.21	
26	865900	(1031900)	432950	(515950)	432950	(515950)	35840450	(17139200)	2.87	
27	763500	(1031900)	381750	(515950)	381750	(515950)	36222200	(17655150)	2.53	
28	661100	(1031900)	330550	(515950)	330550	(515950)	36552750	(18171100)	2.19	
29	558800	(1031900)	279400	(515950)	279400	(515950)	36832150	(18687050)	1.85	
30	456400	(1031900)	228200	(515950)	228200	(515950)	37060350	(19203000)	1.51	
TOT	44206700	(68320000)	22103350	(34160000)	37060350	(19203000)		AVG=	4.89	

Table A-155

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 1000 MW. NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 18888000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 10.9%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	113900	5666600	6890400	(1223800)	5666600	8.00	911200
2	7000	113900	5666600	6775100	(1108500)	5666600	8.00	911200
3	7000	113900	5666600	6659800	(993200)	5666600	8.00	911200
4	7000	113900	5666600	6544500	(877900)	5666600	8.00	911200
5	7000	113900	5666600	6429300	(762700)	5666600	8.00	911200
6	7000	113900	5666600	6314000	(647400)	5666600	8.00	911200
7	7000	113900	5666600	6198700	(532100)	5666600	8.00	911200
8	7000	113900	5666600	6083400	(416800)	5666600	8.00	911200
9	7000	113900	5666600	5968100	(301500)	5666600	8.00	911200
10	7000	113900	5666600	5852800	(186200)	5666600	8.00	911200
11	5000	81300	2968900	5120700	(2151800)	2968900	5.00	406500
12	5000	81300	2968900	5005400	(2036500)	2968900	5.00	406500
13	5000	81300	2968900	4890100	(1921200)	2968900	5.00	406500
14	5000	81300	2968900	4774800	(1805900)	2968900	5.00	406500
15	5000	81300	2968900	4659500	(1690600)	2968900	5.00	406500
16	3500	56900	2331200	4052800	(1721600)	2331200	5.00	284500
17	3500	56900	2331200	3937500	(1606300)	2331200	5.00	284500
18	3500	56900	2331200	3822200	(1491000)	2331200	5.00	284500
19	3500	56900	2331200	3706900	(1375700)	2331200	5.00	284500
20	3500	56900	2331200	3591600	(1260400)	2331200	5.00	284500
21	1500	24400	1399700	2745400	(1345700)	1399700	5.00	122000
22	1500	24400	1399700	2630100	(1230400)	1399700	5.00	122000
23	1500	24400	1399700	2514900	(1115200)	1399700	5.00	122000
24	1500	24400	1399700	2399600	(999900)	1399700	5.00	122000
25	1500	24400	1399700	2284300	(884600)	1399700	5.00	122000
26	1500	24400	1399700	2169000	(769300)	1399700	5.00	122000
27	1500	24400	1399700	2053700	(654000)	1399700	5.00	122000
28	1500	24400	1399700	1938400	(538700)	1399700	5.00	122000
29	1500	24400	1399700	1823100	(423400)	1399700	5.00	122000
30	1500	24400	1399700	1707800	(308100)	1399700	5.00	122000
TOT	127500	2074000	97163500	129543900	(32380400)	97163500		13787000

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 6.0
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	2135000	(4755400)	1067500	(2377700)	2956300	(488900)	2956300	(488900)	5.52	
2	2019700	(4755400)	1009850	(2377700)	2898650	(488900)	5854950	(977800)	5.22	
3	1904400	(4755400)	952200	(2377700)	2841000	(488900)	8695950	(1466700)	4.92	
4	1789100	(4755400)	894550	(2377700)	2783350	(488900)	11479300	(1955600)	4.62	
5	1673900	(4755400)	836950	(2377700)	2725750	(488900)	14205050	(2444500)	4.32	
6	1558600	(4755400)	779300	(2377700)	2668100	(488900)	16873150	(2933400)	4.03	
7	1443300	(4755400)	721650	(2377700)	2610450	(488900)	19483600	(3422300)	3.73	
8	1328000	(4755400)	664000	(2377700)	2552800	(488900)	22036400	(3911200)	3.43	
9	1212700	(4755400)	606350	(2377700)	2495150	(488900)	24531550	(4400100)	3.13	
10	1097400	(4755400)	548700	(2377700)	2437500	(488900)	26969050	(4889000)	2.84	
11	2558300	(2562400)	1279150	(1281200)	1279150	(1281200)	28248200	(6170200)	6.65	
12	2443000	(2562400)	1221500	(1281200)	1221500	(1281200)	29469700	(7451400)	6.35	
13	2327700	(2562400)	1163850	(1281200)	1163850	(1281200)	30633550	(8732600)	6.05	
14	2212400	(2562400)	1106200	(1281200)	1106200	(1281200)	31739750	(10013800)	5.75	
15	2097100	(2562400)	1048550	(1281200)	1048550	(1281200)	32788300	(11295000)	5.45	
16	2006100	(2046700)	1003050	(1023350)	1003050	(1023350)	33791350	(12318350)	5.24	
17	1890800	(2046700)	945400	(1023350)	945400	(1023350)	34736750	(13341700)	4.94	
18	1775500	(2046700)	887750	(1023350)	887750	(1023350)	35624500	(14365050)	4.63	
19	1660200	(2046700)	830100	(1023350)	830100	(1023350)	36454600	(15388400)	4.33	
20	1544900	(2046700)	772450	(1023350)	772450	(1023350)	37227050	(16411750)	4.03	
21	1467700	(1277700)	733850	(638850)	733850	(638850)	37960900	(17050600)	3.86	
22	1352400	(1277700)	676200	(638850)	676200	(638850)	38637100	(17689450)	3.55	
23	1237200	(1277700)	618600	(638850)	618600	(638850)	39255700	(18328300)	3.25	
24	1121900	(1277700)	560950	(638850)	560950	(638850)	39816650	(18967150)	2.95	
25	1006600	(1277700)	503300	(638850)	503300	(638850)	40319950	(19606000)	2.65	
26	891300	(1277700)	445650	(638850)	445650	(638850)	40765600	(20244850)	2.34	
27	776000	(1277700)	388000	(638850)	388000	(638850)	41153600	(20883700)	2.04	
28	660700	(1277700)	330350	(638850)	330350	(638850)	41483950	(21522550)	1.74	
29	545400	(1277700)	272700	(638850)	272700	(638850)	41756650	(22161400)	1.43	
30	430100	(1277700)	215050	(638850)	215050	(638850)	41971700	(22800250)	1.13	
TOT	46167400	(83376500)	23083700	(41688250)	41971700	(22800250)			AVG= 4.04	

Table A-156

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 1000 MW. NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION,

FIXED INVESTMENT = $ 18888000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 15.6%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	113900	5666600	8261100	(2594500)	5666600	8.00	911200
2	7000	113900	5666600	8166900	(2500300)	5666600	8.00	911200
3	7000	113900	5666600	8072700	(2406100)	5666600	8.00	911200
4	7000	113900	5666600	7978500	(2311900)	5666600	8.00	911200
5	7000	113900	5666600	7884300	(2217700)	5666600	8.00	911200
6	7000	113900	5666600	7790200	(2123600)	5666600	8.00	911200
7	7000	113900	5666600	7696000	(2029400)	5666600	8.00	911200
8	7000	113900	5666600	7601800	(1935200)	5666600	8.00	911200
9	7000	113900	5666600	7507600	(1841000)	5666600	8.00	911200
10	7000	113900	5666600	7413400	(1746800)	5666600	8.00	911200
11	5000	81300	2968900	6082300	(3113400)	2968900	5.00	406500
12	5000	81300	2968900	5988200	(3019300)	2968900	5.00	406500
13	5000	81300	2968900	5894000	(2925100)	2968900	5.00	406500
14	5000	81300	2968900	5799800	(2830900)	2968900	5.00	406500
15	5000	81300	2968900	5705600	(2736700)	2968900	5.00	406500
16	3500	56900	2331200	4656200	(2325000)	2331200	5.00	284500
17	3500	56900	2331200	4562000	(2230800)	2331200	5.00	284500
18	3500	56900	2331200	4467900	(2136700)	2331200	5.00	284500
19	3500	56900	2331200	4373700	(2042500)	2331200	5.00	284500
20	3500	56900	2331200	4279500	(1948300)	2331200	5.00	284500
21	1500	24400	1399700	2840700	(1441000)	1399700	5.00	122000
22	1500	24400	1399700	2746500	(1346800)	1399700	5.00	122000
23	1500	24400	1399700	2652400	(1252700)	1399700	5.00	122000
24	1500	24400	1399700	2558200	(1158500)	1399700	5.00	122000
25	1500	24400	1399700	2464000	(1064300)	1399700	5.00	122000
26	1500	24400	1399700	2369800	(970100)	1399700	5.00	122000
27	1500	24400	1399700	2275600	(875900)	1399700	5.00	122000
28	1500	24400	1399700	2181400	(781700)	1399700	5.00	122000
29	1500	24400	1399700	2087300	(687600)	1399700	5.00	122000
30	1500	24400	1399700	1993100	(593400)	1399700	5.00	122000
TOT	127500	2074000	97163500	154350700	(57187200)	97163500		13787000

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 5.3
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	3505700	(4755400)	1752850	(2377700)	3641650	(488900)	3641650	(488900)	9.06	
2	3411500	(4755400)	1705750	(2377700)	3594550	(488900)	7236200	(977800)	8.81	
3	3317300	(4755400)	1658650	(2377700)	3547450	(488900)	10783650	(1466700)	8.57	
4	3223100	(4755400)	1611550	(2377700)	3500350	(488900)	14284000	(1955600)	8.33	
5	3128900	(4755400)	1564450	(2377700)	3453250	(488900)	17737250	(2444500)	8.08	
6	3034800	(4755400)	1517400	(2377700)	3406200	(488900)	21143450	(2933400)	7.84	
7	2940600	(4755400)	1470300	(2377700)	3359100	(488900)	24502550	(3422300)	7.60	
8	2846400	(4755400)	1423200	(2377700)	3312000	(488900)	27814550	(3911200)	7.35	
9	2752200	(4755400)	1376100	(2377700)	3264900	(488900)	31079450	(4400100)	7.11	
10	2658000	(4755400)	1329000	(2377700)	3217800	(488900)	34297250	(4889000)	6.87	
11	3519900	(2562400)	1759950	(1281200)	1759950	(1281200)	36057200	(6170200)	9.15	
12	3425800	(2562400)	1712900	(1281200)	1712900	(1281200)	37770100	(7451400)	8.90	
13	3331600	(2562400)	1665800	(1281200)	1665800	(1281200)	39435900	(8732600)	8.66	
14	3237400	(2562400)	1618700	(1281200)	1618700	(1281200)	41054600	(10013800)	8.41	
15	3143200	(2562400)	1571600	(1281200)	1571600	(1281200)	42626200	(11295000)	8.17	
16	2609500	(2046700)	1304750	(1023350)	1304750	(1023350)	43930950	(12318350)	6.81	
17	2515300	(2046700)	1257650	(1023350)	1257650	(1023350)	45188600	(13341700)	6.57	
18	2421200	(2046700)	1210600	(1023350)	1210600	(1023350)	46399200	(14365050)	6.32	
19	2327000	(2046700)	1163500	(1023350)	1163500	(1023350)	47562700	(15388400)	6.07	
20	2232800	(2046700)	1116400	(1023350)	1116400	(1023350)	48679100	(16411750)	5.83	
21	1563000	(1277700)	781500	(638850)	781500	(638850)	49460600	(17050600)	4.11	
22	1468800	(1277700)	734400	(638850)	734400	(638850)	50195000	(17689450)	3.86	
23	1374700	(1277700)	687350	(638850)	687350	(638850)	50882350	(18328300)	3.61	
24	1280500	(1277700)	640250	(638850)	640250	(638850)	51522600	(18967150)	3.36	
25	1186300	(1277700)	593150	(638850)	593150	(638850)	52115750	(19606000)	3.12	
26	1092100	(1277700)	546050	(638850)	546050	(638850)	52661800	(20244850)	2.87	
27	997900	(1277700)	498950	(638850)	498950	(638850)	53160750	(20883700)	2.62	
28	903700	(1277700)	451850	(638850)	451850	(638850)	53612600	(21522550)	2.37	
29	809600	(1277700)	404800	(638850)	404800	(638850)	54017400	(22161400)	2.13	
30	715400	(1277700)	357700	(638850)	357700	(638850)	54375100	(22800250)	1.88	
TOT	70974200	(83376500)	35487100	(41688250)	54375100	(22800250)			AVG= 6.22	

Table A-157

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 1000 MW. NEW OIL FIRED POWER PLANT, 4.0 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 22046000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 10.5%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	182200	6802800	7717900	(915100)	6802800	8.00	1457600
2	7000	182200	6802800	7591700	(789000)	6802800	8.00	1457600
3	7000	182200	6802800	7465500	(662700)	6802800	8.00	1457600
4	7000	182200	6802800	7339300	(536500)	6802800	8.00	1457600
5	7000	182200	6802800	7213100	(410300)	6802800	8.00	1457600
6	7000	182200	6802800	7086900	(284100)	6802800	8.00	1457600
7	7000	182200	6802800	6960800	(158000)	6802800	8.00	1457600
8	7000	182200	6802800	6834600	(31800)	6802800	8.00	1457600
9	7000	182200	6802800	6708400	94400	6802800	8.00	1457600
10	7000	182200	6802800	6582200	220600	6802800	8.00	1457600
11	5000	130100	3593300	5732700	(2139400)	3593300	5.00	650500
12	5000	130100	3593300	5606500	(2013200)	3593300	5.00	650500
13	5000	130100	3593300	5480300	(1887000)	3593300	5.00	650500
14	5000	130100	3593300	5354100	(1760800)	3593300	5.00	650500
15	5000	130100	3593300	5227900	(1634600)	3593300	5.00	650500
16	3500	91100	2804700	4527300	(1722600)	2804700	5.00	455500
17	3500	91100	2804700	4401100	(1596400)	2804700	5.00	455500
18	3500	91100	2804700	4274900	(1470200)	2804700	5.00	455500
19	3500	91100	2804700	4148700	(1344000)	2804700	5.00	455500
20	3500	91100	2804700	4022500	(1217800)	2804700	5.00	455500
21	1500	39000	1661400	3046900	(1385500)	1661400	5.00	195000
22	1500	39000	1661400	2920800	(1259400)	1661400	5.00	195000
23	1500	39000	1661400	2794600	(1133200)	1661400	5.00	195000
24	1500	39000	1661400	2668400	(1007000)	1661400	5.00	195000
25	1500	39000	1661400	2542200	(880800)	1661400	5.00	195000
26	1500	39000	1661400	2416000	(754600)	1661400	5.00	195000
27	1500	39000	1661400	2289800	(628400)	1661400	5.00	195000
28	1500	39000	1661400	2163600	(502200)	1661400	5.00	195000
29	1500	39000	1661400	2037400	(376000)	1661400	5.00	195000
30	1500	39000	1661400	1911200	(249800)	1661400	5.00	195000
TOT	127500	3318000	116632000	145067300	(28435300)	116632000		22056000

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 6.9
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	2372700	(5345200)	1186350	(2672600)	3390950	(468000)	3390950	(468000)	5.25	
2	2246500	(5345200)	1123250	(2672600)	3327850	(468000)	6718800	(936000)	4.97	
3	2120300	(5345200)	1060150	(2672600)	3264750	(468000)	9983550	(1404000)	4.69	
4	1994100	(5345200)	997050	(2672600)	3201650	(468000)	13185200	(1872000)	4.41	
5	1867900	(5345200)	933950	(2672600)	3138550	(468000)	16323750	(2340000)	4.13	
6	1741700	(5345200)	870850	(2672600)	3075450	(468000)	19399200	(2808000)	3.85	
7	1615600	(5345200)	807800	(2672600)	3012400	(468000)	22411600	(3276000)	3.57	
8	1489400	(5345200)	744700	(2672600)	2949300	(468000)	25360900	(3744000)	3.29	
9	1363200	(5345200)	681600	(2672600)	2886200	(468000)	28247100	(4212000)	3.01	
10	1237000	(5345200)	618500	(2672600)	2823100	(468000)	31070200	(4680000)	2.73	
11	2789900	(2942800)	1394950	(1471400)	1394950	(1471400)	32465150	(6151400)	6.21	
12	2663700	(2942800)	1331850	(1471400)	1331850	(1471400)	33797000	(7622800)	5.92	
13	2537500	(2942800)	1268750	(1471400)	1268750	(1471400)	35065750	(9094200)	5.64	
14	2411300	(2942800)	1205650	(1471400)	1205650	(1471400)	36271400	(10565600)	5.36	
15	2285100	(2942800)	1142550	(1471400)	1142550	(1471400)	37413950	(12037000)	5.08	
16	2178100	(2349200)	1089050	(1174600)	1089050	(1174600)	38503000	(13211600)	4.87	
17	2051900	(2349200)	1025950	(1174600)	1025950	(1174600)	39528950	(14386200)	4.59	
18	1925700	(2349200)	962850	(1174600)	962850	(1174600)	40491800	(15560800)	4.30	
19	1799500	(2349200)	899750	(1174600)	899750	(1174600)	41391550	(16735400)	4.02	
20	1673300	(2349200)	836650	(1174600)	836650	(1174600)	42228200	(17910000)	3.74	
21	1580500	(1466400)	790250	(733200)	790250	(733200)	43018450	(18643200)	3.56	
22	1454400	(1466400)	727200	(733200)	727200	(733200)	43745650	(19376400)	3.27	
23	1328200	(1466400)	664100	(733200)	664100	(733200)	44409750	(20109600)	2.99	
24	1202000	(1466400)	601000	(733200)	601000	(733200)	45010750	(20842800)	2.71	
25	1075800	(1466400)	537900	(733200)	537900	(733200)	45548650	(21576000)	2.42	
26	949600	(1466400)	474800	(733200)	474800	(733200)	46023450	(22309200)	2.14	
27	823400	(1466400)	411700	(733200)	411700	(733200)	46435150	(23042400)	1.85	
28	697200	(1466400)	348600	(733200)	348600	(733200)	46783750	(23775600)	1.57	
29	571000	(1466400)	285500	(733200)	285500	(733200)	47069250	(24508800)	1.29	
30	444800	(1466400)	222400	(733200)	222400	(733200)	47291650	(25242000)	1.00	
TOT	50491300	(94576000)	25245650	(47288000)	47291650	(25242000)			AVG= 3.79	

Table A-158

MAGNESIA SCHEME A, NONREGULATED CO. ECONOMICS, 1000 MW. EXISTING OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 20740000
OVERALL INTEFEST RATE OF RETURN WITH PAYMENT = 10.9%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1								
2								
3								
4	7000	117800	6070600	7604800	(1534200)	6070600	8.00	942400
5	7000	117800	6070600	7463300	(1392700)	6070600	8.00	942400
6	7000	117800	6070600	7321900	(1251300)	6070600	8.00	942400
7	7000	117800	6070600	7180400	(1109800)	6070600	8.00	942400
8	7000	117800	6070600	7039000	(968400)	6070600	8.00	942400
9	7000	117800	6070600	6897500	(826900)	6070600	8.00	942400
10	7000	117800	6070600	6756000	(685400)	6070600	8.00	942400
11	5000	84100	5221800	5942200	(720400)	5221800	8.00	672800
12	5000	84100	5221800	5800700	(578900)	5221800	8.00	672800
13	5000	84100	5221800	5659200	(437400)	5221800	8.00	672800
14	5000	84100	3147800	5517800	(2370000)	3147800	5.00	420500
15	5000	84100	3147800	5376300	(2228500)	3147800	5.00	420500
16	3500	58900	2478200	4699300	(2221100)	2478200	5.00	294500
17	3500	58900	2478200	4557800	(2079600)	2478200	5.00	294500
18	3500	58900	2478200	4416300	(1938100)	2478200	5.00	294500
19	3500	58900	2478200	4274900	(1796700)	2478200	5.00	294500
20	3500	58900	2478200	4133600	(1655200)	2478200	5.00	294500
21	1500	25200	1497000	3195900	(1698900)	1497000	5.00	126000
22	1500	25200	1497000	3054400	(1557400)	1497000	5.00	126000
23	1500	25200	1497000	2912900	(1415900)	1497000	5.00	126000
24	1500	25200	1497000	2771500	(1274500)	1497000	5.00	126000
25	1500	25200	1497000	2630000	(1133000)	1497000	5.00	126000
26	1500	25200	1497000	2488600	(991600)	1497000	5.00	126000
27	1500	25200	1497000	2347100	(850100)	1497000	5.00	126000
28	1500	25200	1497000	2205600	(708600)	1497000	5.00	126000
29	1500	25200	1497000	2064200	(567200)	1497000	5.00	126000
30	1500	25200	1497000	1922700	(425700)	1497000	5.00	126000
TOT	106500	1791600	91816200	126233700	(34417500)	91816200		12188700

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 6.7
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1										
2										
3										
4	2476600	(5128200)	1238300	(2564100)	3312300	(490100)	3312300	(490100)	5.83	
5	2335100	(5128200)	1167550	(2564100)	3241550	(490100)	6553850	(980200)	5.50	
6	2193700	(5128200)	1096850	(2564100)	3170850	(490100)	9724700	(1470300)	5.17	
7	2052200	(5128200)	1026100	(2564100)	3100100	(490100)	12824800	(1960400)	4.83	
8	1910800	(5128200)	955400	(2564100)	3029400	(490100)	15854200	(2450500)	4.50	
9	1769300	(5128200)	884650	(2564100)	2958650	(490100)	18812850	(2940600)	4.17	
10	1627800	(5128200)	813900	(2564100)	2887900	(490100)	21700750	(3430700)	3.83	
11	1393200	(4549000)	696600	(2274500)	2770600	(200500)	24471350	(3631200)	3.30	
12	1251700	(4549000)	625850	(2274500)	2699850	(200500)	27171200	(3831700)	2.96	
13	1110200	(4549000)	555100	(2274500)	2629100	(200500)	29800300	(4032200)	2.63	
14	2790500	(2727300)	1395250	(1363650)	1395250	(1363650)	31195550	(5395850)	6.61	
15	2649000	(2727300)	1324500	(1363650)	1324500	(1363650)	32520050	(6759500)	6.27	
16	2515600	(2183700)	1257800	(1091850)	1257800	(1091850)	33777850	(7851350)	5.98	
17	2374100	(2183700)	1187050	(1091850)	1187050	(1091850)	34964900	(8943200)	5.65	
18	2232600	(2183700)	1116300	(1091850)	1116300	(1091850)	36081200	(10035050)	5.31	
19	2091200	(2183700)	1045600	(1091850)	1045600	(1091850)	37126800	(11126900)	4.97	
20	1949700	(2183700)	974850	(1091850)	974850	(1091850)	38101650	(12218750)	4.64	
21	1824900	(1371000)	912450	(685500)	912450	(685500)	39014100	(12904250)	4.37	
22	1683400	(1371000)	841700	(685500)	841700	(685500)	39855800	(13589750)	4.03	
23	1541900	(1371000)	770950	(685500)	770950	(685500)	40626750	(14275250)	3.69	
24	1400500	(1371000)	700250	(685500)	700250	(685500)	41327000	(14960750)	3.35	
25	1259000	(1371000)	629500	(685500)	629500	(685500)	41956500	(15646250)	3.01	
26	1117600	(1371000)	558800	(685500)	558800	(685500)	42515300	(16331750)	2.68	
27	976100	(1371000)	488050	(685500)	488050	(685500)	43003350	(17017250)	2.34	
28	834600	(1371000)	417300	(685500)	417300	(685500)	43420650	(17702750)	2.00	
29	693200	(1371000)	346600	(685500)	346600	(685500)	43767250	(18388250)	1.66	
30	551700	(1371000)	275850	(685500)	275850	(685500)	44043100	(19073750)	1.32	
TOT	46606200	(7962750)	23303100	(3981375)	44043100	(19073750)			AVG= 4.13	

Table A-159

MAGNESIA SCHEME B, NONREGULATED CO. ECONOMICS, 200 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 11990300
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 6.9%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	45200	3528400	3825400	(297000)	3528400	8.00	361600
2	7000	45200	3528400	3761700	(233300)	3528400	8.00	361600
3	7000	45200	3528400	3698000	(169600)	3528400	8.00	361600
4	7000	45200	3528400	3634200	(105800)	3528400	8.00	361600
5	7000	45200	3528400	3570500	(42100)	3528400	8.00	361600
6	7000	45200	3528400	3506800	21600	3528400	8.00	361600
7	7000	45200	3528400	3443000	85400	3528400	8.00	361600
8	7000	45200	3528400	3379300	149100	3528400	8.00	361600
9	7000	45200	3528400	3315600	212800	3528400	8.00	361600
10	7000	45200	3528400	3251900	276500	3528400	8.00	361600
11	5000	32300	1872400	2868100	(995700)	1872400	5.00	161500
12	5000	32300	1872400	2804400	(932000)	1872400	5.00	161500
13	5000	32300	1872400	2740700	(868300)	1872400	5.00	161500
14	5000	32300	1872400	2676900	(804500)	1872400	5.00	161500
15	5000	32300	1872400	2613200	(740800)	1872400	5.00	161500
16	3500	22600	1502600	2288900	(786300)	1502600	5.00	113000
17	3500	22600	1502600	2225100	(722500)	1502600	5.00	113000
18	3500	22600	1502600	2161400	(658800)	1502600	5.00	113000
19	3500	22600	1502600	2097700	(595100)	1502600	5.00	113000
20	3500	22600	1502600	2033900	(531300)	1502600	5.00	113000
21	1500	9700	939700	1567700	(628000)	939700	5.00	48500
22	1500	9700	939700	1504000	(564300)	939700	5.00	48500
23	1500	9700	939700	1440200	(500500)	939700	5.00	48500
24	1500	9700	939700	1376500	(436800)	939700	5.00	48500
25	1500	9700	939700	1312800	(373100)	939700	5.00	48500
26	1500	9700	939700	1249100	(309400)	939700	5.00	48500
27	1500	9700	939700	1185300	(245600)	939700	5.00	48500
28	1500	9700	939700	1121600	(181900)	939700	5.00	48500
29	1500	9700	939700	1057900	(118200)	939700	5.00	48500
30	1500	9700	939700	996100	(56400)	939700	5.00	48500
TOT	127500	823500	61556000	72705900	(11149900)	61556000		5473500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 8.5
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	658600	(3166800)	329300	(1583400)	1528300	(384400)	1528300	(384400)	2.68	
2	594900	(3166800)	297450	(1583400)	1496450	(384400)	3024750	(768800)	2.42	
3	531200	(3166800)	265600	(1583400)	1464600	(384400)	4489350	(1153200)	2.16	
4	467400	(3166800)	233700	(1583400)	1432700	(384400)	5922050	(1537600)	1.90	
5	403700	(3166800)	201850	(1583400)	1400850	(384400)	7322900	(1922000)	1.64	
6	340000	(3166800)	170000	(1583400)	1369000	(384400)	8691900	(2306400)	1.38	
7	276200	(3166800)	138100	(1583400)	1337100	(384400)	10029000	(2690800)	1.12	
8	212500	(3166800)	106250	(1583400)	1305250	(384400)	11334250	(3075200)	0.87	
9	148800	(3166800)	74400	(1583400)	1273400	(384400)	12607650	(3459600)	0.61	
10	85100	(3166800)	42550	(1583400)	1241550	(384400)	13849200	(3844000)	0.35	
11	1157200	(1710900)	578600	(855450)	578600	(855450)	14427800	(4699450)	4.74	
12	1093500	(1710900)	546750	(855450)	546750	(855450)	14974550	(5554900)	4.48	
13	1029800	(1710900)	514900	(855450)	514900	(855450)	15489450	(6410350)	4.22	
14	966000	(1710900)	483000	(855450)	483000	(855450)	15972450	(7265800)	3.95	
15	902300	(1710900)	451150	(855450)	451150	(855450)	16423600	(8121250)	3.69	
16	899300	(1389600)	449650	(694800)	449650	(694800)	16873250	(8816050)	3.70	
17	835500	(1389600)	417750	(694800)	417750	(694800)	17291000	(9510850)	3.43	
18	771800	(1389600)	385900	(694800)	385900	(694800)	17676900	(10205650)	3.17	
19	708100	(1389600)	354050	(694800)	354050	(694800)	18030950	(10900450)	2.91	
20	644300	(1389600)	322150	(694800)	322150	(694800)	18353100	(11595250)	2.65	
21	676500	(891200)	338250	(445600)	338250	(445600)	18691350	(12040850)	2.80	
22	612800	(891200)	306400	(445600)	306400	(445600)	18997750	(12486450)	2.54	
23	549000	(891200)	274500	(445600)	274500	(445600)	19272250	(12932050)	2.27	
24	485300	(891200)	242650	(445600)	242650	(445600)	19514900	(13377650)	2.01	
25	421600	(891200)	210800	(445600)	210800	(445600)	19725700	(13823250)	1.75	
26	357900	(891200)	178950	(445600)	178950	(445600)	19904650	(14269050)	1.48	
27	294100	(891200)	147050	(445600)	147050	(445600)	20051700	(14714650)	1.22	
28	230400	(891200)	115200	(445600)	115200	(445600)	20166900	(15160050)	0.95	
29	166700	(891200)	83350	(445600)	83350	(445600)	20250250	(15605650)	0.69	
30	102900	(891200)	51450	(445600)	51450	(445600)	20301700	(16051250)	0.43	
TOT	16623400	(56082500)	8311700	(28041250)	20301700	(16051250)			AVG= 2.29	

Table A-160

MAGNESIA SCHEME 8, NONREGULATED CO. ECONOMICS, 200 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 11990000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 10.5%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	45200	3528400	4388700	(860300)	3528400	8.00	361600
2	7000	45200	3528400	4338300	(809900)	3528400	8.00	361600
3	7000	45200	3528400	4288000	(759600)	3528400	8.00	361600
4	7000	45200	3528400	4237700	(709300)	3528400	8.00	361600
5	7000	45200	3528400	4187300	(658900)	3528400	8.00	361600
6	7000	45200	3528400	4137000	(608600)	3528400	8.00	361600
7	7000	45200	3528400	4086700	(558300)	3528400	8.00	361600
8	7000	45200	3528400	4036300	(507900)	3528400	8.00	361600
9	7000	45200	3528400	3986000	(457600)	3528400	8.00	361600
10	7000	45200	3528400	3935700	(407300)	3528400	8.00	361600
11	5000	32300	1872400	3252900	(1380500)	1872400	5.00	161500
12	5000	32300	1872400	3202600	(1330200)	1872400	5.00	161500
13	5000	32300	1872400	3152200	(1279800)	1872400	5.00	161500
14	5000	32300	1872400	3101900	(1229500)	1872400	5.00	161500
15	5000	32300	1872400	3051600	(1179200)	1872400	5.00	161500
16	3500	22600	1502600	2508100	(1005500)	1502600	5.00	113000
17	3500	22600	1502600	2457800	(955200)	1502600	5.00	113000
18	3500	22600	1502600	2407500	(904900)	1502600	5.00	113000
19	3500	22600	1502600	2357100	(854500)	1502600	5.00	113000
20	3500	22600	1502600	2306800	(804200)	1502600	5.00	113000
21	1500	9700	939700	1550300	(610600)	939700	5.00	48500
22	1500	9700	939700	1499900	(560200)	939700	5.00	48500
23	1500	9700	939700	1449600	(509900)	939700	5.00	48500
24	1500	9700	939700	1399300	(459600)	939700	5.00	48500
25	1500	9700	939700	1348900	(409200)	939700	5.00	48500
26	1500	9700	939700	1298600	(358900)	939700	5.00	48500
27	1500	9700	939700	1248200	(308500)	939700	5.00	48500
28	1500	9700	939700	1197900	(258200)	939700	5.00	48500
29	1500	9700	939700	1147600	(207900)	939700	5.00	48500
30	1500	9700	939700	1097200	(157500)	939700	5.00	48500
TOT	127500	823500	61556000	82657700	(21101700)	61556000		5473500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 6.9
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	1221900	(3166800)	610950	(1583400)	1809950	(384400)	1809950	(384400)	4.98	
2	1171500	(3166800)	585750	(1583400)	1784750	(384400)	3594700	(768800)	4.77	
3	1121200	(3166800)	560600	(1583400)	1759600	(384400)	5354300	(1153200)	4.57	
4	1070900	(3166800)	535450	(1583400)	1734450	(384400)	7088750	(1537600)	4.36	
5	1020500	(3166800)	510250	(1583400)	1709250	(384400)	8798000	(1922000)	4.16	
6	970200	(3166800)	485100	(1583400)	1684100	(384400)	10482100	(2306400)	3.95	
7	919900	(3166800)	459950	(1583400)	1658950	(384400)	12141050	(2690800)	3.75	
8	869500	(3166800)	434750	(1583400)	1633750	(384400)	13774800	(3075200)	3.54	
9	819200	(3166800)	409600	(1583400)	1608600	(384400)	15383400	(3459600)	3.34	
10	768900	(3166800)	384450	(1583400)	1583450	(384400)	16966850	(3844000)	3.13	
11	1542000	(1710900)	771000	(855450)	771000	(855450)	17737850	(4699450)	6.31	
12	1491700	(1710900)	745850	(855450)	745850	(855450)	18483700	(5554900)	6.11	
13	1441300	(1710900)	720650	(855450)	720650	(855450)	19204350	(6410350)	5.90	
14	1391000	(1710900)	695500	(855450)	695500	(855450)	19899850	(7265800)	5.69	
15	1340700	(1710900)	670350	(855450)	670350	(855450)	20570200	(8121250)	5.49	
16	1118500	(1389600)	559250	(694800)	559250	(694800)	21129450	(8816050)	4.60	
17	1068200	(1389600)	534100	(694800)	534100	(694800)	21663550	(9510850)	4.39	
18	1017900	(1389600)	508950	(694800)	508950	(694800)	22172500	(10205650)	4.18	
19	967500	(1389600)	483750	(694800)	483750	(694800)	22656250	(10900450)	3.98	
20	917200	(1389600)	458600	(694800)	458600	(694800)	23114850	(11595250)	3.77	
21	659100	(891200)	329550	(445600)	329550	(445600)	23444400	(12040850)	2.73	
22	608700	(891200)	304350	(445600)	304350	(445600)	23748750	(12486450)	2.52	
23	558400	(891200)	279200	(445600)	279200	(445600)	24027950	(12932050)	2.31	
24	508100	(891200)	254050	(445600)	254050	(445600)	24282000	(13377650)	2.10	
25	457700	(891200)	228850	(445600)	228850	(445600)	24510850	(13823250)	1.89	
26	407400	(891200)	203700	(445600)	203700	(445600)	24714550	(14268850)	1.69	
27	357000	(891200)	178500	(445600)	178500	(445600)	24893050	(14714450)	1.48	
28	306700	(891200)	153350	(445600)	153350	(445600)	25046400	(15160050)	1.27	
29	256400	(891200)	128200	(445600)	128200	(445600)	25174600	(15605650)	1.06	
30	206000	(891200)	103000	(445600)	103000	(445600)	25277600	(16051250)	0.85	
TOT	26575200	(56082500)	13287600	(28041250)	25277600	(16051250)			AVG= 3.66	

Table A-161

MAGNESIA SCHEME B, NONREGULATED CO. ECONOMICS, 500 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 22237000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 8.4%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	110400	6404400	7209600	(805200)	6404400	8.00	883200
2	7000	110400	6404400	7087400	(683000)	6404400	8.00	883200
3	7000	110400	6404400	6965200	(560800)	6404400	8.00	883200
4	7000	110400	6404400	6843000	(438600)	6404400	8.00	883200
5	7000	110400	6404400	6720900	(316500)	6404400	8.00	883200
6	7000	110400	6404400	6598700	(194300)	6404400	8.00	883200
7	7000	110400	6404400	6476500	(72100)	6404400	8.00	883200
8	7000	110400	6404400	6354300	50100	6404400	8.00	883200
9	7000	110400	6404400	6232100	172300	6404400	8.00	883200
10	7000	110400	6404400	6110000	294400	6404400	8.00	883200
11	5000	78900	3326700	5381100	(2054400)	3326700	5.00	394500
12	5000	78900	3326700	5258900	(1932200)	3326700	5.00	394500
13	5000	78900	3326700	5136700	(1810000)	3326700	5.00	394500
14	5000	78900	3326700	5014500	(1687800)	3326700	5.00	394500
15	5000	78900	3326700	4892400	(1565700)	3326700	5.00	394500
16	3500	55200	2645500	4280700	(1635200)	2645500	5.00	276000
17	3500	55200	2645500	4158500	(1513000)	2645500	5.00	276000
18	3500	55200	2645500	4036300	(1390800)	2645500	5.00	276000
19	3500	55200	2645500	3914200	(1268700)	2645500	5.00	276000
20	3500	55200	2645500	3792000	(1146500)	2645500	5.00	276000
21	1500	23700	1629000	2926100	(1297100)	1629000	5.00	118500
22	1500	23700	1629000	2803900	(1174900)	1629000	5.00	118500
23	1500	23700	1629000	2681700	(1052700)	1629000	5.00	118500
24	1500	23700	1629000	2559600	(930600)	1629000	5.00	118500
25	1500	23700	1629000	2437400	(808400)	1629000	5.00	118500
26	1500	23700	1629000	2315200	(686200)	1629000	5.00	118500
27	1500	23700	1629000	2193000	(564000)	1629000	5.00	118500
28	1500	23700	1629000	2070800	(441800)	1629000	5.00	118500
29	1500	23700	1629000	1948700	(319700)	1629000	5.00	118500
30	1500	23700	1629000	1826500	(197500)	1629000	5.00	118500
TOT	127500	2011500	110195000	136225900	(26030900)	110195000		13369500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 7.8
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	1688400	(5521200)	844200	(2760600)	3067900	(536900)	3067900	(536900)	3.71	
2	1566200	(5521200)	783100	(2760600)	3006800	(536900)	6074700	(1073800)	3.44	
3	1444000	(5521200)	722000	(2760600)	2945700	(536900)	9020400	(1610700)	3.17	
4	1321800	(5521200)	660900	(2760600)	2884500	(536900)	11905000	(2147600)	2.91	
5	1199700	(5521200)	599850	(2760600)	2823550	(536900)	14728550	(2684500)	2.64	
6	1077500	(5521200)	538750	(2760600)	2762450	(536900)	17491000	(3221400)	2.37	
7	955300	(5521200)	477650	(2760600)	2701350	(536900)	20192350	(3758300)	2.10	
8	833100	(5521200)	416550	(2760600)	2640250	(536900)	22832600	(4295200)	1.83	
9	710900	(5521200)	355450	(2760600)	2579150	(536900)	25411750	(4832100)	1.56	
10	588800	(5521200)	294400	(2760600)	2518100	(536900)	27929850	(5369000)	1.29	
11	2448900	(2932200)	1224450	(1466100)	1224450	(1466100)	29154300	(6835100)	5.41	
12	2326700	(2932200)	1163350	(1466100)	1163350	(1466100)	30317650	(8301200)	5.14	
13	2204500	(2932200)	1102250	(1466100)	1102250	(1466100)	31419900	(9767300)	4.87	
14	2082300	(2932200)	1041150	(1466100)	1041150	(1466100)	32461050	(11233400)	4.60	
15	1960200	(2932200)	980100	(1466100)	980100	(1466100)	33441150	(12699500)	4.33	
16	1911200	(2369500)	955600	(1184750)	955600	(1184750)	34396750	(13884250)	4.24	
17	1789000	(2369500)	894500	(1184750)	894500	(1184750)	35291250	(15069000)	3.97	
18	1666800	(2369500)	833400	(1184750)	833400	(1184750)	36124650	(16253750)	3.70	
19	1544700	(2369500)	772350	(1184750)	772350	(1184750)	36897000	(17438500)	3.43	
20	1422500	(2369500)	711250	(1184750)	711250	(1184750)	37608250	(18623250)	3.16	
21	1415600	(1510500)	707800	(755250)	707800	(755250)	38316050	(19378500)	3.16	
22	1293400	(1510500)	646700	(755250)	646700	(755250)	38962750	(20133750)	2.89	
23	1171200	(1510500)	585600	(755250)	585600	(755250)	39548350	(20889000)	2.61	
24	1049100	(1510500)	524550	(755250)	524550	(755250)	40072900	(21644250)	2.34	
25	926900	(1510500)	463450	(755250)	463450	(755250)	40536350	(22399500)	2.07	
26	804700	(1510500)	402350	(755250)	402350	(755250)	40938700	(23154750)	1.80	
27	682500	(1510500)	341250	(755250)	341250	(755250)	41279950	(23910000)	1.52	
28	560300	(1510500)	280150	(755250)	280150	(755250)	41560100	(24665250)	1.25	
29	438200	(1510500)	219100	(755250)	219100	(755250)	41779200	(25420500)	0.98	
30	316000	(1510500)	158000	(755250)	158000	(755250)	41937200	(26175750)	0.71	
TOT	39400400	(96825500)	19700200	(48412750)	41937200	(26175750)			AVG= 2.93	

Table A-162

MAGNESIA SCHEME B, NONREGULATED CO. ECONOMICS, 500 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 22237000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 14.4%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY NET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	110400	6404400	9115900	(2711500)	6404400	8.00	883200
2	7000	110400	6404400	9016300	(2611900)	6404400	8.00	883200
3	7000	110400	6404400	8916700	(2512300)	6404400	8.00	883200
4	7000	110400	6404400	8817100	(2412700)	6404400	8.00	883200
5	7000	110400	6404400	8717600	(2313200)	6404400	8.00	883200
6	7000	110400	6404400	8618000	(2213600)	6404400	8.00	883200
7	7000	110400	6404400	8518400	(2114000)	6404400	8.00	883200
8	7000	110400	6404400	8418800	(2014400)	6404400	8.00	883200
9	7000	110400	6404400	8319200	(1914800)	6404400	8.00	883200
10	7000	110400	6404400	8219600	(1815200)	6404400	8.00	883200
11	5000	78900	3326700	6719600	(3392900)	3326700	5.00	394500
12	5000	78900	3326700	6620000	(3293300)	3326700	5.00	394500
13	5000	78900	3326700	6520400	(3193700)	3326700	5.00	394500
14	5000	78900	3326700	6420800	(3094100)	3326700	5.00	394500
15	5000	78900	3326700	6321200	(2994500)	3326700	5.00	394500
16	3500	55200	2645500	5139500	(2494000)	2645500	5.00	276000
17	3500	55200	2645500	5039900	(2394400)	2645500	5.00	276000
18	3500	55200	2645500	4940300	(2294800)	2645500	5.00	276000
19	3500	55200	2645500	4840700	(2195200)	2645500	5.00	276000
20	3500	55200	2645500	4741100	(2095600)	2645500	5.00	276000
21	1500	23700	1629000	3114300	(1485300)	1629000	5.00	118500
22	1500	23700	1629000	3014700	(1385700)	1629000	5.00	118500
23	1500	23700	1629000	2915100	(1286100)	1629000	5.00	118500
24	1500	23700	1629000	2815500	(1186500)	1629000	5.00	118500
25	1500	23700	1629000	2715900	(1086900)	1629000	5.00	118500
26	1500	23700	1629000	2616400	(987400)	1629000	5.00	118500
27	1500	23700	1629000	2516800	(887800)	1629000	5.00	118500
28	1500	23700	1629000	2417200	(788200)	1629000	5.00	118500
29	1500	23700	1629000	2317600	(688600)	1629000	5.00	118500
30	1500	23700	1629000	2218000	(589000)	1629000	5.00	118500
TOT	127500	2011500	110195000	170642600	(60447600)	110195000		13369500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 5.7
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	3594700	(5521200)	1797350	(2760600)	4021050	(536900)	4021050	(536900)	7.90	
2	3495100	(5521200)	1747550	(2760600)	3971250	(536900)	7992300	(1073800)	7.68	
3	3395500	(5521200)	1697750	(2760600)	3921450	(536900)	11913750	(1610700)	7.46	
4	3295900	(5521200)	1647950	(2760600)	3871650	(536900)	15785400	(2147600)	7.24	
5	3196400	(5521200)	1598200	(2760600)	3821900	(536900)	19607300	(2684500)	7.02	
6	3096800	(5521200)	1548400	(2760600)	3772100	(536900)	23379400	(3221400)	6.81	
7	2997200	(5521200)	1498600	(2760600)	3722300	(536900)	27101700	(3758300)	6.59	
8	2897600	(5521200)	1448800	(2760600)	3672500	(536900)	30774200	(4295200)	6.37	
9	2798000	(5521200)	1399000	(2760600)	3622700	(536900)	34396900	(4832100)	6.15	
10	2698400	(5521200)	1349200	(2760600)	3572900	(536900)	37969800	(5369000)	5.93	
11	3787400	(2932200)	1893700	(1466100)	1893700	(1466100)	39863500	(6835100)	8.37	
12	3687800	(2932200)	1843900	(1466100)	1843900	(1466100)	41707400	(8301200)	8.15	
13	3588200	(2932200)	1794100	(1466100)	1794100	(1466100)	43501500	(9767300)	7.93	
14	3488600	(2932200)	1744300	(1466100)	1744300	(1466100)	45245800	(11233400)	7.71	
15	3389000	(2932200)	1694500	(1466100)	1694500	(1466100)	46940300	(12699500)	7.49	
16	2770000	(2369500)	1385000	(1184750)	1385000	(1184750)	48325300	(13884250)	6.15	
17	2670400	(2369500)	1335200	(1184750)	1335200	(1184750)	49660500	(15069000)	5.92	
18	2570800	(2369500)	1285400	(1184750)	1285400	(1184750)	50945900	(16253750)	5.70	
19	2471200	(2369500)	1235600	(1184750)	1235600	(1184750)	52181500	(17438500)	5.48	
20	2371600	(2369500)	1185800	(1184750)	1185800	(1184750)	53367300	(18623250)	5.26	
21	1603800	(1510500)	801900	(755250)	801900	(755250)	54169200	(19378500)	3.58	
22	1504200	(1510500)	752100	(755250)	752100	(755250)	54921300	(20133750)	3.36	
23	1404600	(1510500)	702300	(755250)	702300	(755250)	55623600	(20889000)	3.14	
24	1305000	(1510500)	652500	(755250)	652500	(755250)	56276100	(21644250)	2.91	
25	1205400	(1510500)	602700	(755250)	602700	(755250)	56878800	(22399500)	2.69	
26	1105900	(1510500)	552950	(755250)	552950	(755250)	57431750	(23154750)	2.47	
27	1006300	(1510500)	503150	(755250)	503150	(755250)	57934900	(23910000)	2.25	
28	906700	(1510500)	453350	(755250)	453350	(755250)	58388250	(24665250)	2.02	
29	807100	(1510500)	403550	(755250)	403550	(755250)	58791800	(25420500)	1.80	
30	707500	(1510500)	353750	(755250)	353750	(755250)	59145550	(26175750)	1.58	
TOT	73817100	(96825500)	36908550	(48412750)	59145550	(26175750)			AVG= 5.49	

Table A-163

MAGNESIA SCHEME E, NONREGULATED CO. ECONOMICS, 1000 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 33838000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 9.6%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	213500	9657200	11082800	(1425600)	9657200	8.00	1708000
2	7000	213500	9657200	10892700	(1235500)	9657200	8.00	1708000
3	7000	213500	9657200	10702700	(1045500)	9657200	8.00	1708000
4	7000	213500	9657200	10512600	(855400)	9657200	8.00	1708000
5	7000	213500	9657200	10322500	(665300)	9657200	8.00	1708000
6	7000	213500	9657200	10132500	(475300)	9657200	8.00	1708000
7	7000	213500	9657200	9942400	(285200)	9657200	8.00	1708000
8	7000	213500	9657200	9752300	(95100)	9657200	8.00	1708000
9	7000	213500	9657200	9562200	95000	9657200	8.00	1708000
10	7000	213500	9657200	9372200	285000	9657200	8.00	1708000
11	5000	152500	4943300	8236300	(3293000)	4943300	5.00	762500
12	5000	152500	4943300	8046200	(3102900)	4943300	5.00	762500
13	5000	152500	4943300	7856200	(2912900)	4943300	5.00	762500
14	5000	152500	4943300	7666100	(2722800)	4943300	5.00	762500
15	5000	152500	4943300	7476000	(2532700)	4943300	5.00	762500
16	3500	106800	3893900	6530600	(2636700)	3893900	5.00	534000
17	3500	106800	3893900	6340600	(2446700)	3893900	5.00	534000
18	3500	106800	3893900	6150500	(2256600)	3893900	5.00	534000
19	3500	106800	3893900	5960400	(2066500)	3893900	5.00	534000
20	3500	106800	3893900	5770400	(1876500)	3893900	5.00	534000
21	1500	45800	2359100	4451700	(2092600)	2359100	5.00	229000
22	1500	45800	2359100	4261600	(1902500)	2359100	5.00	229000
23	1500	45800	2359100	4071600	(1712500)	2359100	5.00	229000
24	1500	45800	2359100	3881500	(1522400)	2359100	5.00	229000
25	1500	45800	2359100	3691400	(1332300)	2359100	5.00	229000
26	1500	45800	2359100	3501300	(1142200)	2359100	5.00	229000
27	1500	45800	2359100	3311300	(952200)	2359100	5.00	229000
28	1500	45800	2359100	3121200	(762100)	2359100	5.00	229000
29	1500	45800	2359100	2931100	(572000)	2359100	5.00	229000
30	1500	45800	2359100	2741100	(382000)	2359100	5.00	229000
TOT	127500	3889500	164349000	208272000	(43923000)	164349000		25852500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 7.3
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	3133600	(7949200)	1566800	(3974600)	4950600	(590800)	4950600	(590800)	4.53	
2	2943500	(7949200)	1471750	(3974600)	4855550	(590800)	9806150	(1181600)	4.25	
3	2753500	(7949200)	1376750	(3974600)	4760550	(590800)	14566700	(1772400)	3.98	
4	2563400	(7949200)	1281700	(3974600)	4665500	(590800)	19232200	(2363200)	3.70	
5	2373300	(7949200)	1186650	(3974600)	4570450	(590800)	23802650	(2954000)	3.43	
6	2183300	(7949200)	1091650	(3974600)	4475450	(590800)	28278100	(3544800)	3.15	
7	1993200	(7949200)	996600	(3974600)	4380400	(590800)	32658500	(4135600)	2.88	
8	1803100	(7949200)	901550	(3974600)	4285350	(590800)	36943850	(4726400)	2.60	
9	1613000	(7949200)	806500	(3974600)	4190300	(590800)	41134150	(5317200)	2.33	
10	1423000	(7949200)	711500	(3974600)	4095300	(590800)	45229450	(5908000)	2.06	
11	4055500	(4180800)	2027750	(2090400)	2027750	(2090400)	47257200	(7998400)	5.89	
12	3865400	(4180800)	1932700	(2090400)	1932700	(2090400)	49189900	(10088800)	5.61	
13	3675400	(4180800)	1837700	(2090400)	1837700	(2090400)	51027600	(12179200)	5.34	
14	3485300	(4180800)	1742650	(2090400)	1742650	(2090400)	52770250	(14269600)	5.06	
15	3295200	(4180800)	1647600	(2090400)	1647600	(2090400)	54417850	(16360000)	4.79	
16	3170700	(3359900)	1585350	(1679950)	1585350	(1679950)	56003200	(18039950)	4.62	
17	2980700	(3359900)	1490350	(1679950)	1490350	(1679950)	57493550	(19719900)	4.35	
18	2790600	(3359900)	1395300	(1679950)	1395300	(1679950)	58888850	(21399850)	4.07	
19	2600500	(3359900)	1300250	(1679950)	1300250	(1679950)	60189100	(23079800)	3.79	
20	2410500	(3359900)	1205250	(1679950)	1205250	(1679950)	61394350	(24759750)	3.52	
21	2321600	(2130100)	1160800	(1065050)	1160800	(1065050)	62555150	(25824800)	3.41	
22	2131500	(2130100)	1065750	(1065050)	1065750	(1065050)	63620900	(26889850)	3.13	
23	1941500	(2130100)	970750	(1065050)	970750	(1065050)	64591650	(27954900)	2.85	
24	1751400	(2130100)	875700	(1065050)	875700	(1065050)	65467350	(29019950)	2.57	
25	1561300	(2130100)	780650	(1065050)	780650	(1065050)	66248000	(30085000)	2.29	
26	1371200	(2130100)	685600	(1065050)	685600	(1065050)	66933600	(31150050)	2.01	
27	1181200	(2130100)	590600	(1065050)	590600	(1065050)	67524200	(32215100)	1.73	
28	991100	(2130100)	495550	(1065050)	495550	(1065050)	68019750	(33280150)	1.45	
29	801000	(2130100)	400500	(1065050)	400500	(1065050)	68420250	(34345200)	1.18	
30	611000	(2130100)	305500	(1065050)	305500	(1065050)	68725750	(35410250)	0.90	
TOT	69775500	(138496500)	34887750	(69248250)	68725750	(35410250)		AVG=	3.41	

Table A-164

MAGNESIA SCHEME B, NONREGULATED CO. ECONOMICS, 1000 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 33838000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 17.6%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	213500	9657200	15208800	(5551600)	9657200	8.00	1708000
2	7000	213500	9657200	15053700	(5396500)	9657200	8.00	1708000
3	7000	213500	9657200	14898600	(5241400)	9657200	8.00	1708000
4	7000	213500	9657200	14743500	(5086300)	9657200	8.00	1708000
5	7000	213500	9657200	14588400	(4931200)	9657200	8.00	1708000
6	7000	213500	9657200	14433200	(4776000)	9657200	8.00	1708000
7	7000	213500	9657200	14278100	(4620900)	9657200	8.00	1708000
8	7000	213500	9657200	14123000	(4465800)	9657200	8.00	1708000
9	7000	213500	9657200	13967900	(4310700)	9657200	8.00	1708000
10	7000	213500	9657200	13812800	(4155600)	9657200	8.00	1708000
11	5000	152500	4943300	11154900	(6211600)	4943300	5.00	762500
12	5000	152500	4943300	10999800	(6056500)	4943300	5.00	762500
13	5000	152500	4943300	10844700	(5901400)	4943300	5.00	762500
14	5000	152500	4943300	10689600	(5746300)	4943300	5.00	762500
15	5000	152500	4943300	10534500	(5591200)	4943300	5.00	762500
16	3500	106800	3893900	8458700	(4564800)	3893900	5.00	534000
17	3500	106800	3893900	8303600	(4409700)	3893900	5.00	534000
18	3500	106800	3893900	8148500	(4254600)	3893900	5.00	534000
19	3500	106800	3893900	7993400	(4099500)	3893900	5.00	534000
20	3500	106800	3893900	7838300	(3944400)	3893900	5.00	534000
21	1500	45800	2359100	5007900	(2648800)	2359100	5.00	229000
22	1500	45800	2359100	4852800	(2493700)	2359100	5.00	229000
23	1500	45800	2359100	4697700	(2338600)	2359100	5.00	229000
24	1500	45800	2359100	4542500	(2183400)	2359100	5.00	229000
25	1500	45800	2359100	4387400	(2028300)	2359100	5.00	229000
26	1500	45800	2359100	4232300	(1873200)	2359100	5.00	229000
27	1500	45800	2359100	4077200	(1718100)	2359100	5.00	229000
28	1500	45800	2359100	3922100	(1563000)	2359100	5.00	229000
29	1500	45800	2359100	3767000	(1407900)	2359100	5.00	229000
30	1500	45800	2359100	3611900	(1252800)	2359100	5.00	229000
TOT	127500	3889500	164349000	283172800	(118823800)	164349000		25852500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 4.9
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	7259600	(7949200)	3629800	(3974600)	7013600	(590800)	7013600	(590800)	10.49	
2	7104500	(7949200)	3552250	(3974600)	6936050	(590800)	13949650	(1181600)	10.26	
3	6949400	(7949200)	3474700	(3974600)	6858500	(590800)	20808150	(1772400)	10.04	
4	6794300	(7949200)	3397150	(3974600)	6780950	(590800)	27589100	(2363200)	9.82	
5	6639200	(7949200)	3319600	(3974600)	6703400	(590800)	34292500	(2954000)	9.59	
6	6484000	(7949200)	3242000	(3974600)	6625800	(590800)	40918300	(3544800)	9.37	
7	6328900	(7949200)	3164450	(3974600)	6548250	(590800)	47466550	(4135600)	9.14	
8	6173800	(7949200)	3086900	(3974600)	6470700	(590800)	53937250	(4726400)	8.92	
9	6018700	(7949200)	3009350	(3974600)	6393150	(590800)	60330400	(5317200)	8.69	
10	5863600	(7949200)	2931800	(3974600)	6315600	(590800)	66646000	(5908000)	8.47	
11	6974100	(4180800)	3487050	(2090400)	3487050	(2090400)	70133050	(7998400)	10.13	
12	6819000	(4180800)	3409500	(2090400)	3409500	(2090400)	73542550	(10088800)	9.90	
13	6663900	(4180800)	3331950	(2090400)	3331950	(2090400)	76874500	(12179200)	9.68	
14	6508800	(4180800)	3254400	(2090400)	3254400	(2090400)	80128900	(14269600)	9.45	
15	6353700	(4180800)	3176850	(2090400)	3176850	(2090400)	83305750	(16360000)	9.23	
16	5098800	(3359900)	2549400	(1679950)	2549400	(1679950)	85855150	(18039950)	7.44	
17	4943700	(3359900)	2471850	(1679950)	2471850	(1679950)	88327000	(19719900)	7.21	
18	4788600	(3359900)	2394300	(1679950)	2394300	(1679950)	90721300	(21399850)	6.98	
19	4633500	(3359900)	2316750	(1679950)	2316750	(1679950)	93038050	(23079800)	6.76	
20	4478400	(3359900)	2239200	(1679950)	2239200	(1679950)	95277250	(24759750)	6.53	
21	2877800	(2130100)	1438900	(1065050)	1438900	(1065050)	96716150	(25824800)	4.22	
22	2722700	(2130100)	1361350	(1065050)	1361350	(1065050)	98077500	(26889850)	4.00	
23	2567600	(2130100)	1283800	(1065050)	1283800	(1065050)	99361300	(27954900)	3.77	
24	2412400	(2130100)	1206200	(1065050)	1206200	(1065050)	100567500	(29019950)	3.54	
25	2257300	(2130100)	1128650	(1065050)	1128650	(1065050)	101696150	(30085000)	3.31	
26	2102200	(2130100)	1051100	(1065050)	1051100	(1065050)	102747250	(31150050)	3.09	
27	1947100	(2130100)	973550	(1065050)	973550	(1065050)	103720800	(32215100)	2.86	
28	1792000	(2130100)	896000	(1065050)	896000	(1065050)	104616800	(33280150)	2.63	
29	1636900	(2130100)	818450	(1065050)	818450	(1065050)	105435250	(34345200)	2.40	
30	1481800	(2130100)	740900	(1065050)	740900	(1065050)	106176150	(35410250)	2.17	
TOT	144676300	(138496500)	72338150	(69248250)	106176150	(35410250)			AVG= 7.00	

Table A-165

MAGNESIA SCHEME B, NONREGULATED CO. ECONOMICS, 200 MW. NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 6806000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 9.1%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	24100	2039700	2429700	(390000)	2039700	8.00	192800
2	7000	24100	2039700	2390200	(350500)	2039700	8.00	192800
3	7000	24100	2039700	2350700	(311000)	2039700	8.00	192800
4	7000	24100	2039700	2311100	(271400)	2039700	8.00	192800
5	7000	24100	2039700	2271600	(231900)	2039700	8.00	192800
6	7000	24100	2039700	2232100	(192400)	2039700	8.00	192800
7	7000	24100	2039700	2192600	(152900)	2039700	8.00	192800
8	7000	24100	2039700	2153100	(113400)	2039700	8.00	192800
9	7000	24100	2039700	2113500	(73800)	2039700	8.00	192800
10	7000	24100	2039700	2076000	(36300)	2039700	8.00	192800
11	5000	17200	1100200	1826600	(726400)	1100200	5.00	86000
12	5000	17200	1100200	1787100	(686900)	1100200	5.00	86000
13	5000	17200	1100200	1747600	(647400)	1100200	5.00	86000
14	5000	17200	1100200	1708000	(607800)	1100200	5.00	86000
15	5000	17200	1100200	1668500	(568300)	1100200	5.00	86000
16	3500	12000	888800	1459000	(570200)	888800	5.00	60000
17	3500	12000	888800	1419500	(530700)	888800	5.00	60000
18	3500	12000	888800	1380000	(491200)	888800	5.00	60000
19	3500	12000	888800	1340400	(451600)	888800	5.00	60000
20	3500	12000	888800	1300900	(412100)	888800	5.00	60000
21	1500	5200	562400	997500	(435100)	562400	5.00	26000
22	1500	5200	562400	958000	(395600)	562400	5.00	26000
23	1500	5200	562400	918500	(356100)	562400	5.00	26000
24	1500	5200	562400	878900	(316500)	562400	5.00	26000
25	1500	5200	562400	839400	(277000)	562400	5.00	26000
26	1500	5200	562400	799900	(237500)	562400	5.00	26000
27	1500	5200	562400	760400	(198000)	562400	5.00	26000
28	1500	5200	562400	720900	(158500)	562400	5.00	26000
29	1500	5200	562400	681300	(118900)	562400	5.00	26000
30	1500	5200	562400	641800	(79400)	562400	5.00	26000
TOT	127500	439000	35966000	46352800	(10386800)	35966000		2918000

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 7.5
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	582800	(1846900)	291400	(923450)	972000	(242850)	972000	(242850)	4.18	
2	543300	(1846900)	271650	(923450)	952250	(242850)	1924250	(485700)	3.90	
3	503800	(1846900)	251900	(923450)	932500	(242850)	2856750	(728550)	3.61	
4	464200	(1846900)	232100	(923450)	912700	(242850)	3769450	(971400)	3.33	
5	424700	(1846900)	212350	(923450)	892950	(242850)	4662400	(1214250)	3.05	
6	385200	(1846900)	192600	(923450)	873200	(242850)	5535600	(1457100)	2.76	
7	345700	(1846900)	172850	(923450)	853450	(242850)	6389050	(1699950)	2.48	
8	306200	(1846900)	153100	(923450)	833700	(242850)	7222750	(1942800)	2.20	
9	266600	(1846900)	133300	(923450)	813900	(242850)	8036650	(2185650)	1.91	
10	227100	(1846900)	113550	(923450)	796150	(242850)	8830800	(2428500)	1.63	
11	812400	(1014200)	406200	(507100)	406200	(507100)	9237000	(2935600)	5.86	
12	772900	(1014200)	386450	(507100)	386450	(507100)	9623450	(3442700)	5.57	
13	733400	(1014200)	366700	(507100)	366700	(507100)	9990150	(3949800)	5.29	
14	693800	(1014200)	346900	(507100)	346900	(507100)	10337050	(4456900)	5.00	
15	654300	(1014200)	327150	(507100)	327150	(507100)	10664200	(4964000)	4.72	
16	630200	(828800)	315100	(414400)	315100	(414400)	10979300	(5378400)	4.56	
17	590700	(828800)	295350	(414400)	295350	(414400)	11274650	(5792800)	4.28	
18	551200	(828800)	275600	(414400)	275600	(414400)	11550250	(6207200)	3.99	
19	511600	(828800)	255800	(414400)	255800	(414400)	11806050	(6621600)	3.70	
20	472100	(828800)	236050	(414400)	236050	(414400)	12042100	(7036000)	3.42	
21	461100	(536400)	230550	(268200)	230550	(268200)	12272650	(7304200)	3.36	
22	421600	(536400)	210800	(268200)	210800	(268200)	12483450	(7572400)	3.07	
23	382100	(536400)	191050	(268200)	191050	(268200)	12674500	(7840600)	2.78	
24	342500	(536400)	171250	(268200)	171250	(268200)	12845750	(8108800)	2.49	
25	303000	(536400)	151500	(268200)	151500	(268200)	12997250	(8377000)	2.21	
26	263500	(536400)	131750	(268200)	131750	(268200)	13129000	(8645200)	1.92	
27	224000	(536400)	112000	(268200)	112000	(268200)	13241000	(8913400)	1.63	
28	184500	(536400)	92250	(268200)	92250	(268200)	13333250	(9181600)	1.34	
29	144900	(536400)	72450	(268200)	72450	(268200)	13405700	(9449800)	1.06	
30	105400	(536400)	52700	(268200)	52700	(268200)	13458400	(9718000)	0.77	
TOT	13304800	(33048000)	6652400	(16524000)	13458400	(9718000)			AVG= 3.23	

Table A-168

MAGNESIA SCHEME B, NONREGULATED CO. ECONOMICS, 200 MW. NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 6806000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 10.1%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	24100	2039700	2514300 (	474600)	2039700	8.00	192800
2	7000	24100	2039700	2483200 (	443500)	2039700	8.00	192900
3	7000	24100	2039700	2452000 (	412300)	2039700	8.00	192800
4	7000	24100	2039700	2420900 (	381200)	2039700	8.00	192900
5	7000	24100	2039700	2389700 (	350000)	2039700	8.00	192800
6	7000	24100	2039700	2358600 (	318900)	2039700	8.00	192800
7	7000	24100	2039700	2327400 (	287700)	2039700	8.00	192800
8	7000	24100	2039700	2296200 (	256500)	2039700	8.00	192400
9	7000	24100	2039700	2265100 (	225400)	2039700	8.00	192800
10	7000	24100	2039700	2233900 (	194200)	2039700	8.00	192800
11	5000	17200	1100200	1875000 (	774800)	1100200	5.00	86000
12	5000	17200	1100200	1843800 (	743600)	1100200	5.00	86000
13	5000	17200	1100200	1812600 (	712400)	1100200	5.00	86000
14	5000	17200	1100200	1781500 (	681300)	1100200	5.00	96000
15	5000	17200	1100200	1750300 (	650100)	1100200	5.00	86000
16	3500	12000	888800	1460900 (	572100)	888800	5.00	60000
17	3500	12000	888800	1429700 (	540900)	888800	5.00	60000
18	3500	12000	888800	1398600 (	509800)	888800	5.00	60000
19	3500	12000	888800	1367400 (	478600)	888800	5.00	60000
20	3500	12000	888800	1336200 (	447400)	888800	5.00	60000
21	1500	5200	562400	927600 (	365200)	562400	5.00	26000
22	1500	5200	562400	896400 (	334000)	562400	5.00	26000
23	1500	5200	562400	865300 (	302900)	562400	5.00	26000
24	1500	5200	562400	834100 (	271700)	562400	5.00	26000
25	1500	5200	562400	802900 (	240500)	562400	5.00	26000
26	1500	5200	562400	771800 (	209400)	562400	5.00	26000
27	1500	5200	562400	740600 (	178200)	562400	5.00	26000
28	1500	5200	562400	709500 (	147100)	562400	5.00	26000
29	1500	5200	562400	678300 (	115900)	562400	5.00	26000
30	1500	5200	562400	647200 (	84800)	562400	5.00	26000
TOT	127500	439000	35966000	47671000 (	11705000)	35966000		2918000

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 7.0
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	667400 (	1846900)	333700 (	923450)	1014300 (	242850)	1014300 (	242850)	4.79	
2	636300 (	1846900)	318150 (	923450)	998750 (	242850)	2013050 (	485700)	4.56	
3	605100 (	1846900)	302550 (	923450)	983150 (	242850)	2996200 (	728550)	4.34	
4	574000 (	1846900)	287000 (	923450)	967600 (	242850)	3963800 (	971400)	4.12	
5	542800 (	1846900)	271400 (	923450)	952000 (	242850)	4915800 (	1214250)	3.89	
6	511700 (	1846900)	255850 (	923450)	936450 (	242850)	5852250 (	1457100)	3.67	
7	480500 (	1846900)	240250 (	923450)	920850 (	242850)	6773100 (	1699950)	3.45	
8	449300 (	1846900)	224650 (	923450)	905250 (	242850)	7678350 (	1942800)	3.22	
9	418200 (	1846900)	209100 (	923450)	889700 (	242850)	8568050 (	2185650)	3.00	
10	387000 (	1846900)	193500 (	923450)	874100 (	242850)	9442150 (	2428500)	2.78	
11	860800 (	1014200)	430400 (	507100)	430400 (	507100)	9872550 (	2935600)	6.20	
12	829600 (	1014200)	414800 (	507100)	414800 (	507100)	10287350 (	3442700)	5.98	
13	798400 (	1014200)	399200 (	507100)	399200 (	507100)	10686550 (	3949800)	5.75	
14	767300 (	1014200)	383650 (	507100)	383650 (	507100)	11070200 (	4456900)	5.53	
15	736100 (	1014200)	368050 (	507100)	368050 (	507100)	11438250 (	4964000)	5.31	
16	632100 (	828800)	316050 (	414400)	316050 (	414400)	11754300 (	5378400)	4.57	
17	600900 (	828800)	300450 (	414400)	300450 (	414400)	12054750 (	5792800)	4.35	
18	569800 (	828800)	284900 (	414400)	284900 (	414400)	12339650 (	6207200)	4.12	
19	538600 (	828800)	269300 (	414400)	269300 (	414400)	12608950 (	6621600)	3.90	
20	507400 (	828800)	253700 (	414400)	253700 (	414400)	12862650 (	7036000)	3.67	
21	391200 (	536400)	195600 (	268200)	195600 (	268200)	13058250 (	7304200)	2.85	
22	360000 (	536400)	180000 (	268200)	180000 (	268200)	13238250 (	7572400)	2.62	
23	328900 (	536400)	164450 (	268200)	164450 (	268200)	13402700 (	7840600)	2.40	
24	297700 (	536400)	148850 (	268200)	148850 (	268200)	13551550 (	8108800)	2.17	
25	266500 (	536400)	133250 (	268200)	133250 (	268200)	13684800 (	8377000)	1.94	
26	235400 (	536400)	117700 (	268200)	117700 (	268200)	13802500 (	8645200)	1.71	
27	204200 (	536400)	102100 (	268200)	102100 (	268200)	13904600 (	8913400)	1.49	
28	173100 (	536400)	86550 (	268200)	86550 (	268200)	13991150 (	9181600)	1.26	
29	141900 (	536400)	70950 (	268200)	70950 (	268200)	14062100 (	9449800)	1.03	
30	110800 (	536400)	55400 (	268200)	55400 (	268200)	14117500 (	9718000)	0.81	
TOT	14623000 (	33048000)	7311500 (	16524000)	14117500 (	9718000)			AVG= 3.55	

Table A-167

MAGNESIA SCHEME B, NONREGULATED CO. ECONOMICS, 500 MW. NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H_2SO_4 PRODUCTION.

FIXED INVESTMENT = $ 12561000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 10.3%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H_2SO_4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H_2SO_4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	58900	3625100	4454500	(829400)	3625100	8.00	471200
2	7000	58900	3625100	4308500	(683400)	3625100	8.00	471200
3	7000	58900	3625100	4306400	(681300)	3625100	8.00	471200
4	7000	58900	3625100	4232400	(607300)	3625100	8.00	471200
5	7000	58900	3625100	4158300	(533200)	3625100	8.00	471200
6	7000	58900	3625100	4084300	(459200)	3625100	8.00	471200
7	7000	58900	3625100	4010200	(385100)	3625100	8.00	471200
8	7000	58900	3625100	3936200	(311100)	3625100	8.00	471200
9	7000	58900	3625100	3862100	(237000)	3625100	8.00	471200
10	7000	58900	3625100	3788100	(163000)	3625100	8.00	471200
11	5000	42100	1894600	3325700	(1431100)	1894600	5.00	210500
12	5000	42100	1894600	3251600	(1357000)	1894600	5.00	210500
13	5000	42100	1894600	3177600	(1283000)	1894600	5.00	210500
14	5000	42100	1894600	3103500	(1208900)	1894600	5.00	210500
15	5000	42100	1894600	3029500	(1134900)	1894600	5.00	210500
16	3500	29400	1514100	2642700	(1128600)	1514100	5.00	147000
17	3500	29400	1514100	2568700	(1054600)	1514100	5.00	147000
18	3500	29400	1514100	2494600	(980500)	1514100	5.00	147000
19	3500	29400	1514100	2420600	(906500)	1514100	5.00	147000
20	3500	29400	1514100	2346500	(832400)	1514100	5.00	147000
21	1500	12600	941100	1798300	(857200)	941100	5.00	63000
22	1500	12600	941100	1724200	(783100)	941100	5.00	63000
23	1500	12600	941100	1650200	(709100)	941100	5.00	63000
24	1500	12600	941100	1576100	(635000)	941100	5.00	63000
25	1500	12600	941100	1502100	(561000)	941100	5.00	63000
26	1500	12600	941100	1428000	(486900)	941100	5.00	63000
27	1500	12600	941100	1354000	(412900)	941100	5.00	63000
28	1500	12600	941100	1279900	(338800)	941100	5.00	63000
29	1500	12600	941100	1205900	(264800)	941100	5.00	63000
30	1500	12600	941100	1131800	(190700)	941100	5.00	63000
TOT	127500	1072500	62705500	84152500	(21447000)	62705500		7129500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 7.0
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	1300600	(3153900)	650300	(1576950)	1906400	(320850)	1906400	(320850)	5.06	
2	1154600	(3153900)	577300	(1576950)	1833400	(320850)	3739800	(641700)	4.49	
3	1152500	(3153900)	576250	(1576950)	1832350	(320850)	5572150	(962550)	4.48	
4	1078500	(3153900)	539250	(1576950)	1795350	(320850)	7367500	(1283400)	4.20	
5	1004400	(3153900)	502200	(1576950)	1758300	(320850)	9125800	(1604250)	3.91	
6	930400	(3153900)	465200	(1576950)	1721300	(320850)	10847100	(1925100)	3.62	
7	856300	(3153900)	428150	(1576950)	1684250	(320850)	12531350	(2245950)	3.33	
8	782300	(3153900)	391150	(1576950)	1647250	(320850)	14178600	(2566800)	3.04	
9	708200	(3153900)	354100	(1576950)	1610200	(320850)	15788800	(2887650)	2.76	
10	634200	(3153900)	317100	(1576950)	1573200	(320850)	17362000	(3208500)	2.47	
11	1641600	(1684100)	820800	(842050)	820800	(842050)	18182800	(4050550)	6.42	
12	1567500	(1684100)	783750	(842050)	783750	(842050)	18966550	(4892600)	6.13	
13	1493500	(1684100)	746750	(842050)	746750	(842050)	19713300	(5734650)	5.84	
14	1419400	(1684100)	709700	(842050)	709700	(842050)	20423000	(6576700)	5.55	
15	1345400	(1684100)	672700	(842050)	672700	(842050)	21095700	(7418750)	5.26	
16	1275600	(1367100)	637800	(683550)	637800	(683550)	21733500	(8102300)	5.01	
17	1201600	(1367100)	600800	(683550)	600800	(683550)	22334300	(8785850)	4.72	
18	1127500	(1367100)	563750	(683550)	563750	(683550)	22898050	(9469400)	4.43	
19	1053500	(1367100)	526750	(683550)	526750	(683550)	23424800	(10152950)	4.14	
20	979400	(1367100)	489700	(683550)	489700	(683550)	23914500	(10836500)	3.85	
21	920200	(878100)	460100	(439050)	460100	(439050)	24374600	(11275550)	3.64	
22	846100	(878100)	423050	(439050)	423050	(439050)	24797650	(11714600)	3.34	
23	772100	(878100)	386050	(439050)	386050	(439050)	25183700	(12153650)	3.05	
24	698000	(878100)	349000	(439050)	349000	(439050)	25532700	(12592700)	2.76	
25	624000	(878100)	312000	(439050)	312000	(439050)	25844700	(13031750)	2.47	
26	549900	(878100)	274950	(439050)	274950	(439050)	26119650	(13470800)	2.17	
27	475900	(878100)	237950	(439050)	237950	(439050)	26357600	(13909850)	1.88	
28	401800	(878100)	200900	(439050)	200900	(439050)	26558500	(14348900)	1.59	
29	327800	(878100)	163900	(439050)	163900	(439050)	26722400	(14787950)	1.30	
30	253700	(878100)	126850	(439050)	126850	(439050)	26849250	(15227000)	1.00	
TOT	28576500	(55576000)	14288250	(27788000)	26849250	(15227000)			AVG= 3.76	

Table A-168

MAGNESIA SCHEME B, NONREGULATED CO. ECONOMICS, 500 MW, NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 12561000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 13.9%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	58900	3625100	5015800	(1390700)	3625100	8.00	471200
2	7000	58900	3625100	4955600	(1330500)	3625100	8.00	471200
3	7000	58900	3625100	4895400	(1270300)	3625100	8.00	471200
4	7000	58900	3625100	4835200	(1210100)	3625100	8.00	471200
5	7000	58900	3625100	4775000	(1149900)	3625100	8.00	471200
6	7000	58900	3625100	4714800	(1089700)	3625100	8.00	471200
7	7000	58900	3625100	4654600	(1029500)	3625100	8.00	471200
8	7000	58900	3625100	4594400	(969300)	3625100	8.00	471200
9	7000	58900	3625100	4534200	(909100)	3625100	8.00	471200
10	7000	58900	3625100	4474000	(848900)	3625100	8.00	471200
11	5000	42100	1894600	3712000	(1817400)	1894600	5.00	210500
12	5000	42100	1894600	3651800	(1757200)	1894600	5.00	210500
13	5000	42100	1894600	3591600	(1697000)	1894600	5.00	210500
14	5000	42100	1894600	3531400	(1636800)	1894600	5.00	210500
15	5000	42100	1894600	3471200	(1576600)	1894600	5.00	210500
16	3500	29400	1514100	2865100	(1351000)	1514100	5.00	147000
17	3500	29400	1514100	2804900	(1290800)	1514100	5.00	147000
18	3500	29400	1514100	2744700	(1230600)	1514100	5.00	147000
19	3500	29400	1514100	2684600	(1170500)	1514100	5.00	147000
20	3500	29400	1514100	2624400	(1110300)	1514100	5.00	147000
21	1500	12600	941100	1783400	(842300)	941100	5.00	63000
22	1500	12600	941100	1723200	(782100)	941100	5.00	63000
23	1500	12600	941100	1663000	(721900)	941100	5.00	63000
24	1500	12600	941100	1602800	(661700)	941100	5.00	63000
25	1500	12600	941100	1542600	(601500)	941100	5.00	63000
26	1500	12600	941100	1482400	(541300)	941100	5.00	63000
27	1500	12600	941100	1422200	(481100)	941100	5.00	63000
28	1500	12600	941100	1362000	(420900)	941100	5.00	63000
29	1500	12600	941100	1301800	(360700)	941100	5.00	63000
30	1500	12600	941100	1241600	(300500)	941100	5.00	63000
TOT	127500	1072500	62705500	94255700	(31550200)	62705500		7129500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 5.9
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	1861900	(3153900)	930950	(1576950)	2187050	(320850)	2187050	(320850)	7.24	
2	1801700	(3153900)	900850	(1576950)	2156950	(320850)	4344000	(641700)	7.01	
3	1741500	(3153900)	870750	(1576950)	2126850	(320850)	6470850	(962550)	6.78	
4	1681300	(3153900)	840650	(1576950)	2096750	(320850)	8567600	(1283400)	6.54	
5	1621100	(3153900)	810550	(1576950)	2066650	(320850)	10634250	(1604250)	6.31	
6	1560900	(3153900)	780450	(1576950)	2036550	(320850)	12670800	(1925100)	6.07	
7	1500700	(3153900)	750350	(1576950)	2006450	(320850)	14677250	(2245950)	5.84	
8	1440500	(3153900)	720250	(1576950)	1976350	(320850)	16653600	(2566800)	5.60	
9	1380300	(3153900)	690150	(1576950)	1946250	(320850)	18599850	(2887650)	5.37	
10	1320100	(3153900)	660050	(1576950)	1916150	(320850)	20516000	(3208500)	5.14	
11	2027900	(1684100)	1013950	(842050)	1013950	(842050)	21529950	(4050550)	7.93	
12	1967700	(1684100)	983850	(842050)	983850	(842050)	22513800	(4892600)	7.69	
13	1907500	(1684100)	953750	(842050)	953750	(842050)	23467550	(5734650)	7.46	
14	1847300	(1684100)	923650	(842050)	923650	(842050)	24391200	(6576700)	7.22	
15	1787100	(1684100)	893550	(842050)	893550	(842050)	25284750	(7418750)	6.99	
16	1498000	(1367100)	749000	(683550)	749000	(683550)	26033750	(8102300)	5.88	
17	1437800	(1367100)	718900	(683550)	718900	(683550)	26752650	(8785850)	5.65	
18	1377600	(1367100)	688800	(683550)	688800	(683550)	27441450	(9469400)	5.41	
19	1317500	(1367100)	658750	(683550)	658750	(683550)	28100200	(10152950)	5.17	
20	1257300	(1367100)	628650	(683550)	628650	(683550)	28728850	(10836500)	4.94	
21	905300	(878100)	452650	(439050)	452650	(439050)	29181500	(11275550)	3.58	
22	845100	(878100)	422550	(439050)	422550	(439050)	29604050	(11714600)	3.34	
23	784900	(878100)	392450	(439050)	392450	(439050)	29996500	(12153650)	3.10	
24	724700	(878100)	362350	(439050)	362350	(439050)	30358850	(12592700)	2.86	
25	664500	(878100)	332250	(439050)	332250	(439050)	30691100	(13031750)	2.62	
26	604300	(878100)	302150	(439050)	302150	(439050)	30993250	(13470800)	2.39	
27	544100	(878100)	272050	(439050)	272050	(439050)	31265300	(13909850)	2.15	
28	483900	(878100)	241950	(439050)	241950	(439050)	31507250	(14348900)	1.91	
29	423700	(878100)	211850	(439050)	211850	(439050)	31719100	(14787950)	1.67	
30	363500	(878100)	181750	(439050)	181750	(439050)	31900850	(15227000)	1.43	
TOT	38679700	(55576000)	19339850	(27788000)	31900850	(15227000)			AVG= 5.09	

Table A-169

MAGNESIA SCHEME 6, NONREGULATED CO. ECONOMICS, 1000 MW, NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 19126000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 11.9%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	113900	5477000	6890400	(1413400)	5477000	8.00	911200
2	7000	113900	5477000	6775100	(1298100)	5477000	8.00	911200
3	7000	113900	5477000	6659800	(1182800)	5477000	8.00	911200
4	7000	113900	5477000	6544500	(1067500)	5477000	8.00	911200
5	7000	113900	5477000	6429300	(952300)	5477000	8.00	911200
6	7000	113900	5477000	6314000	(837000)	5477000	8.00	911200
7	7000	113900	5477000	6198700	(721700)	5477000	8.00	911200
8	7000	113900	5477000	6083400	(606400)	5477000	8.00	911200
9	7000	113900	5477000	5968100	(491100)	5477000	8.00	911200
10	7000	113900	5477000	5852800	(375800)	5477000	8.00	911200
11	5000	81300	2819200	5120700	(2301500)	2819200	5.00	406500
12	5000	81300	2819200	5005400	(2186200)	2819200	5.00	406500
13	5000	81300	2819200	4890100	(2070900)	2819200	5.00	406500
14	5000	81300	2819200	4774800	(1955600)	2819200	5.00	406500
15	5000	81300	2819200	4659500	(1840300)	2819200	5.00	406500
16	3500	56900	2229100	4052800	(1823700)	2229100	5.00	284500
17	3500	56900	2229100	3937500	(1708400)	2229100	5.00	284500
18	3500	56900	2229100	3822200	(1593100)	2229100	5.00	284500
19	3500	56900	2229100	3706900	(1477800)	2229100	5.00	284500
20	3500	56900	2229100	3591600	(1362500)	2229100	5.00	284500
21	1500	24400	1360300	2745400	(1385100)	1360300	5.00	122000
22	1500	24400	1360300	2630100	(1269800)	1360300	5.00	122000
23	1500	24400	1360300	2514900	(1154600)	1360300	5.00	122000
24	1500	24400	1360300	2399600	(1039300)	1360300	5.00	122000
25	1500	24400	1360300	2286300	(926000)	1360300	5.00	122000
26	1500	24400	1360300	2169000	(808700)	1360300	5.00	122000
27	1500	24400	1360300	2053700	(693400)	1360300	5.00	122000
28	1500	24400	1360300	1938400	(578100)	1360300	5.00	122000
29	1500	24400	1360300	1823100	(462800)	1360300	5.00	122000
30	1500	24400	1360300	1707800	(347500)	1360300	5.00	122000
TOT	127500	2074000	93614500	129543900	(35929400)	93614500		13787000

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 6.6
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	2324600	(4565800)	1162300	(2282900)	3074900	(370300)	3074900	(370300)	5.94	
2	2209300	(4565800)	1104650	(2282900)	3017250	(370300)	6092150	(740600)	5.65	
3	2094000	(4565800)	1047000	(2282900)	2959600	(370300)	9051750	(1110900)	5.35	
4	1978700	(4565800)	989350	(2282900)	2901950	(370300)	11953700	(1481200)	5.06	
5	1863500	(4565800)	931750	(2282900)	2844350	(370300)	14798050	(1851500)	4.76	
6	1748200	(4565800)	874100	(2282900)	2786700	(370300)	17584750	(2221800)	4.47	
7	1632900	(4565800)	816450	(2282900)	2729050	(370300)	20313800	(2592100)	4.17	
8	1517600	(4565800)	758800	(2282900)	2671400	(370300)	22985200	(2962400)	3.88	
9	1402300	(4565800)	701150	(2282900)	2613750	(370300)	25598950	(3332700)	3.58	
10	1287000	(4565800)	643500	(2282900)	2556100	(370300)	28155050	(3703000)	3.29	
11	2708000	(2412700)	1354000	(1206350)	1354000	(1206350)	29509050	(4909350)	6.96	
12	2592700	(2412700)	1296350	(1206350)	1296350	(1206350)	30805400	(6115700)	6.66	
13	2477400	(2412700)	1238700	(1206350)	1238700	(1206350)	32044100	(7322050)	6.36	
14	2362100	(2412700)	1181050	(1206350)	1181050	(1206350)	33225150	(8528400)	6.07	
15	2246800	(2412700)	1123400	(1206350)	1123400	(1206350)	34348550	(9734750)	5.77	
16	2108200	(1944600)	1054100	(972300)	1054100	(972300)	35402650	(10707050)	5.44	
17	1992900	(1944600)	996450	(972300)	996450	(972300)	36399100	(11679350)	5.14	
18	1877600	(1944600)	938800	(972300)	938800	(972300)	37337900	(12651650)	4.84	
19	1762300	(1944600)	881150	(972300)	881150	(972300)	38219050	(13623950)	4.55	
20	1647000	(1944600)	823500	(972300)	823500	(972300)	39042550	(14596250)	4.25	
21	1507100	(1238300)	753550	(619150)	753550	(619150)	39796100	(15215400)	3.91	
22	1391800	(1238300)	695900	(619150)	695900	(619150)	40492000	(15834550)	3.61	
23	1276600	(1238300)	638300	(619150)	638300	(619150)	41130300	(16453700)	3.31	
24	1161300	(1238300)	580650	(619150)	580650	(619150)	41710950	(17072850)	3.01	
25	1046000	(1238300)	523000	(619150)	523000	(619150)	42233950	(17692000)	2.72	
26	930700	(1238300)	465350	(619150)	465350	(619150)	42699300	(18311150)	2.42	
27	815400	(1238300)	407700	(619150)	407700	(619150)	43107000	(18930300)	2.12	
28	700100	(1238300)	350050	(619150)	350050	(619150)	43457050	(19549450)	1.82	
29	584800	(1238300)	292400	(619150)	292400	(619150)	43749450	(20168600)	1.52	
30	469500	(1238300)	234750	(619150)	234750	(619150)	43984200	(20787750)	1.22	
TOT	49716400	(79827500)	24858200	(39913750)	43984200	(20787750)			AVG= 4.30	

Table A-170

MAGNESIA SCHEME B, NONREGULATED CO. ECONOMICS, 1000 MW. NEW OIL FIRED POWER PLANT, 2.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 19126000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 16.2%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NFG

Payment equivalent to projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR		NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
					WITH PAYMENT	WITHOUT PAYMENT		
1	7000	113900	5477000	8261100	(2784100)	5477000	8.00	911200
2	7000	113900	5477000	8166900	(2689900)	5477000	8.00	911200
3	7000	113900	5477000	8072700	(2595700)	5477000	8.00	911200
4	7000	113900	5477000	7978500	(2501500)	5477000	8.00	911200
5	7000	113900	5477000	7884300	(2407300)	5477000	8.00	911200
6	7000	113900	5477000	7790200	(2313200)	5477000	8.00	911200
7	7000	113900	5477000	7696000	(2219000)	5477000	8.00	911200
8	7000	113900	5477000	7601800	(2124800)	5477000	8.00	911200
9	7000	113900	5477000	7507600	(2030600)	5477000	8.00	911200
10	7000	113900	5477000	7413400	(1936400)	5477000	8.00	911200
11	5000	81300	2819200	6082300	(3263100)	2819200	5.00	406500
12	5000	81300	2819200	5988200	(3169000)	2819200	5.00	406500
13	5000	81300	2819200	5894000	(3074800)	2819200	5.00	406500
14	5000	81300	2819200	5799800	(2980600)	2819200	5.00	406500
15	5000	81300	2819200	5705600	(2886400)	2819200	5.00	406500
16	3500	56900	2229100	4656200	(2427100)	2229100	5.00	284500
17	3500	56900	2229100	4562000	(2332900)	2229100	5.00	284500
18	3500	56900	2229100	4467900	(2238800)	2229100	5.00	284500
19	3500	56900	2229100	4373700	(2144600)	2229100	5.00	284500
20	3500	56900	2229100	4279500	(2050400)	2229100	5.00	284500
21	1500	24400	1360300	2840700	(1480400)	1360300	5.00	122000
22	1500	24400	1360300	2746500	(1386200)	1360300	5.00	122000
23	1500	24400	1360300	2652400	(1292100)	1360300	5.00	122000
24	1500	24400	1360300	2558200	(1197900)	1360300	5.00	122000
25	1500	24400	1360300	2464000	(1103700)	1360300	5.00	122000
26	1500	24400	1360300	2369800	(1009500)	1360300	5.00	122000
27	1500	24400	1360300	2275600	(915300)	1360300	5.00	122000
28	1500	24400	1360300	2181400	(821100)	1360300	5.00	122000
29	1500	24400	1360300	2087300	(727000)	1360300	5.00	122000
30	1500	24400	1360300	1993100	(632800)	1360300	5.00	122000
TOT	127500	2074000	93614500	154350700	(60736200)	93614500		13787000

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 5.2
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR		NET INCOME AFTER TAXES, $/YEAR		CASH FLOW, $/YEAR		CUMULATIVE CASH FLOW, $		ANNUAL RETURN ON INITIAL INVESTMENT, %	
	WITH PAYMENT	WITHOUT PAYMENT	WITH PAYMENT	WITHOUT PAYMENT	WITH PAYMENT	WITHOUT PAYMENT	WITH PAYMENT	WITHOUT PAYMENT	WITH PAYMENT	WITHOUT PAYMENT
1	3695300	(4565800)	1847650	(2282900)	3760250	(370300)	3760250	(370300)	9.44	
2	3601100	(4565800)	1800550	(2282900)	3713150	(370300)	7473400	(740600)	9.20	
3	3506900	(4565800)	1753450	(2282900)	3666050	(370300)	11139450	(1110900)	8.96	
4	3412700	(4565800)	1706350	(2282900)	3618950	(370300)	14758400	(1481200)	8.72	
5	3318500	(4565800)	1659250	(2282900)	3571850	(370300)	18330250	(1851500)	8.48	
6	3224400	(4565800)	1612200	(2282900)	3524800	(370300)	21855050	(2221800)	8.24	
7	3130200	(4565800)	1565100	(2282900)	3477700	(370300)	25332750	(2592100)	8.00	
8	3036000	(4565800)	1518000	(2282900)	3430600	(370300)	28763350	(2962400)	7.76	
9	2941800	(4565800)	1470900	(2282900)	3383500	(370300)	32146850	(3332700)	7.52	
10	2847600	(4565800)	1423800	(2282900)	3336400	(370300)	35483250	(3703000)	7.28	
11	3669600	(2412700)	1834800	(1206350)	1834800	(1206350)	37318050	(4909350)	9.43	
12	3575500	(2412700)	1787750	(1206350)	1787750	(1206350)	39105800	(6115700)	9.19	
13	3481300	(2412700)	1740650	(1206350)	1740650	(1206350)	40846450	(7322050)	8.94	
14	3387100	(2412700)	1693550	(1206350)	1693550	(1206350)	42540000	(8528400)	8.70	
15	3292900	(2412700)	1646450	(1206350)	1646450	(1206350)	44186450	(9734750)	8.46	
16	2711600	(1944600)	1355800	(972300)	1355800	(972300)	45542250	(10707050)	7.00	
17	2617400	(1944600)	1308700	(972300)	1308700	(972300)	46850950	(11679350)	6.75	
18	2523300	(1944600)	1261650	(972300)	1261650	(972300)	48112600	(12651650)	6.51	
19	2429100	(1944600)	1214550	(972300)	1214550	(972300)	49327150	(13623950)	6.27	
20	2334900	(1944600)	1167450	(972300)	1167450	(972300)	50494600	(14596250)	6.02	
21	1602300	(1238300)	801200	(619150)	801200	(619150)	51295800	(15215400)	4.16	
22	1508200	(1238300)	754100	(619150)	754100	(619150)	52049900	(15834550)	3.92	
23	1414100	(1238300)	707050	(619150)	707050	(619150)	52756950	(16453700)	3.67	
24	1319900	(1238300)	659950	(619150)	659950	(619150)	53416900	(17072850)	3.43	
25	1225700	(1238300)	612850	(619150)	612850	(619150)	54029750	(17692000)	3.18	
26	1131500	(1238300)	565750	(619150)	565750	(619150)	54595500	(18311150)	2.94	
27	1037300	(1238300)	518650	(619150)	518650	(619150)	55114150	(18930300)	2.69	
28	943100	(1238300)	471550	(619150)	471550	(619150)	55585700	(19549450)	2.45	
29	849000	(1238300)	424500	(619150)	424500	(619150)	56010200	(20168600)	2.20	
30	754800	(1238300)	377400	(619150)	377400	(619150)	56387600	(20787750)	1.96	
TOT	74523200	(79827500)	37261600	(39913750)	56387600	(20787750)			AVG= 6.45	

Table A-171

MAGNESIA SCHEME C, NONREGULATED CO. ECONOMICS, 200 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 9923000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 10.7%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY NET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR		NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
					WITH PAYMENT	WITHOUT PAYMENT		
1	7000	38700	3044600	3825400	(780800)	3044600	8.00	309600
2	7000	38700	3044600	3761700	(717100)	3044600	8.00	309600
3	7000	38700	3044600	3698000	(653400)	3044600	8.00	309600
4	7000	38700	3044600	3634200	(589600)	3044600	8.00	309600
5	7000	38700	3044600	3570500	(525900)	3044600	8.00	309600
6	7000	38700	3044600	3506800	(462200)	3044600	8.00	309600
7	7000	38700	3044600	3443000	(398400)	3044600	8.00	309600
8	7000	38700	3044600	3379300	(334700)	3044600	8.00	309600
9	7000	38700	3044600	3315600	(271000)	3044600	8.00	309600
10	7000	38700	3044600	3251900	(207300)	3044600	8.00	309600
11	5000	27700	1643900	2868100	(1224200)	1643900	5.00	138500
12	5000	27700	1643900	2804400	(1160500)	1643900	5.00	138500
13	5000	27700	1643900	2740700	(1096800)	1643900	5.00	138500
14	5000	27700	1643900	2676900	(1033000)	1643900	5.00	138500
15	5000	27700	1643900	2613200	(969300)	1643900	5.00	138500
16	3500	19400	1314200	2288900	(974700)	1314200	5.00	97000
17	3500	19400	1314200	2225100	(910900)	1314200	5.00	97000
18	3500	19400	1314200	2161400	(847200)	1314200	5.00	97000
19	3500	19400	1314200	2097700	(783500)	1314200	5.00	97000
20	3500	19400	1314200	2033900	(719700)	1314200	5.00	97000
21	1500	8300	814400	1567700	(753300)	814400	5.00	41500
22	1500	8300	814400	1504000	(689600)	814400	5.00	41500
23	1500	8300	814400	1440200	(625800)	814400	5.00	41500
24	1500	8300	814400	1376500	(562100)	814400	5.00	41500
25	1500	8300	814400	1312800	(498400)	814400	5.00	41500
26	1500	8300	814400	1249100	(434700)	814400	5.00	41500
27	1500	8300	814400	1185300	(370900)	814400	5.00	41500
28	1500	8300	814400	1121600	(307200)	814400	5.00	41500
29	1500	8300	814400	1057900	(243500)	814400	5.00	41500
30	1500	8300	814400	994100	(179700)	814400	5.00	41500
TOT	127500	705500	53380500	72705900	(19325400)	53380500		4688500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 6.9
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR		NET INCOME AFTER TAXES, $/YEAR		CASH FLOW, $/YEAR		CUMULATIVE CASH FLOW, $		ANNUAL RETURN ON INITIAL INVESTMENT, %	
	WITH PAYMENT	WITHOUT PAYMENT	WITH PAYMENT	WITHOUT PAYMENT	WITH PAYMENT	WITHOUT PAYMENT	WITH PAYMENT	WITHOUT PAYMENT	WITH PAYMENT	WITHOUT PAYMENT
1	1090400	(2735000)	545200	(1367500)	1537500	(375200)	1537500	(375200)	5.36	
2	1026700	(2735000)	513350	(1367500)	1505650	(375200)	3043150	(750400)	5.05	
3	963000	(2735000)	481500	(1367500)	1473800	(375200)	4516950	(1125600)	4.73	
4	899200	(2735000)	449600	(1367500)	1441900	(375200)	5958850	(1500800)	4.42	
5	835500	(2735000)	417750	(1367500)	1410050	(375200)	7368900	(1876000)	4.11	
6	771800	(2735000)	385900	(1367500)	1378200	(375200)	8747100	(2251200)	3.79	
7	708000	(2735000)	354000	(1367500)	1346300	(375200)	10093400	(2626400)	3.48	
8	644300	(2735000)	322150	(1367500)	1314450	(375200)	11407850	(3001600)	3.17	
9	580600	(2735000)	290300	(1367500)	1282600	(375200)	12690450	(3376800)	2.85	
10	516900	(2735000)	258450	(1367500)	1250750	(375200)	13941200	(3752000)	2.54	
11	1362700	(1505400)	681350	(752700)	681350	(752700)	14622550	(4504700)	6.73	
12	1299000	(1505400)	649500	(752700)	649500	(752700)	15272050	(5257400)	6.42	
13	1235300	(1505400)	617650	(752700)	617650	(752700)	15889700	(6010100)	6.10	
14	1171500	(1505400)	585750	(752700)	585750	(752700)	16475450	(6762800)	5.79	
15	1107800	(1505400)	553900	(752700)	553900	(752700)	17029350	(7515500)	5.47	
16	1071700	(1217200)	535850	(608600)	535850	(608600)	17565200	(8124100)	5.32	
17	1007900	(1217200)	503950	(608600)	503950	(608600)	18069150	(8732700)	5.00	
18	944200	(1217200)	472100	(608600)	472100	(608600)	18541250	(9341300)	4.69	
19	880500	(1217200)	440250	(608600)	440250	(608600)	18981500	(9949900)	4.37	
20	816700	(1217200)	408350	(608600)	408350	(608600)	19389850	(10558500)	4.05	
21	794800	(772900)	397400	(386450)	397400	(386450)	19787250	(10944950)	3.97	
22	731100	(772900)	365550	(386450)	365550	(386450)	20152800	(11331400)	3.65	
23	667300	(772900)	333650	(386450)	333650	(386450)	20486450	(11717850)	3.33	
24	603600	(772900)	301800	(386450)	301800	(386450)	20788250	(12104300)	3.02	
25	539900	(772900)	269950	(386450)	269950	(386450)	21058200	(12490750)	2.70	
26	476200	(772900)	238100	(386450)	238100	(386450)	21296300	(12877200)	2.38	
27	412400	(772900)	206200	(386450)	206200	(386450)	21502500	(13263650)	2.06	
28	348700	(772900)	174350	(386450)	174350	(386450)	21676850	(13650100)	1.74	
29	285000	(772900)	142500	(386450)	142500	(386450)	21819350	(14036550)	1.42	
30	221200	(772900)	110600	(386450)	110600	(386450)	21929950	(14423000)	1.11	
TOT	24013900	(48692000)	12006950	(24346000)	21929950	(14423000)			AVG= 4.00	

Table A-172

MAGNESIA SCHEME C, NONREGULATED CO. ECONOMICS, 200 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 9923000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 14.6%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	38700	3044600	4388700	(1344100)	3044600	8.00	309600
2	7000	38700	3044600	4338300	(1293700)	3044600	8.00	309600
3	7000	38700	3044600	4288000	(1243400)	3044600	8.00	309600
4	7000	38700	3044600	4237700	(1193100)	3044600	8.00	309600
5	7000	38700	3044600	4187300	(1142700)	3044600	8.00	309600
6	7000	38700	3044600	4137000	(1092400)	3044600	8.00	309600
7	7000	38700	3044600	4086700	(1042100)	3044600	8.00	309600
8	7000	38700	3044600	4036300	(991700)	3044600	8.00	309600
9	7000	38700	3044600	3986000	(941400)	3044600	8.00	309600
10	7000	38700	3044600	3935700	(891100)	3044600	8.00	309600
11	5000	27700	1643900	3252900	(1609000)	1643900	5.00	138500
12	5000	27700	1643900	3202600	(1558700)	1643900	5.00	138500
13	5000	27700	1643900	3152200	(1508300)	1643900	5.00	138500
14	5000	27700	1643900	3101900	(1458000)	1643900	5.00	138500
15	5000	27700	1643900	3051600	(1407700)	1643900	5.00	138500
16	3500	19400	1314200	2508100	(1193900)	1314200	5.00	97000
17	3500	19400	1314200	2457800	(1143600)	1314200	5.00	97000
18	3500	19400	1314200	2407500	(1093300)	1314200	5.00	97000
19	3500	19400	1314200	2357100	(1042900)	1314200	5.00	97000
20	3500	19400	1314200	2306800	(992600)	1314200	5.00	97000
21	1500	8300	814400	1550300	(735900)	814400	5.00	41500
22	1500	8300	814400	1499900	(685500)	814400	5.00	41500
23	1500	8300	814400	1449600	(635200)	814400	5.00	41500
24	1500	8300	814400	1399300	(584900)	814400	5.00	41500
25	1500	8300	814400	1348900	(534500)	814400	5.00	41500
26	1500	8300	814400	1298600	(484200)	814400	5.00	41500
27	1500	8300	814400	1248200	(433800)	814400	5.00	41500
28	1500	8300	814400	1197900	(383500)	814400	5.00	41500
29	1500	8300	814400	1147600	(333200)	814400	5.00	41500
30	1500	8300	814400	1097200	(282800)	814400	5.00	41500
TOT	127500	705500	53380500	82657700	(29277200)	53380500		4688500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 5.6
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	1653700	(2735000)	826850	(1367500)	1819150	(375200)	1819150	(375200)	8.13	
2	1603300	(2735000)	801650	(1367500)	1793950	(375200)	3613100	(750400)	7.88	
3	1553000	(2735000)	776500	(1367500)	1768800	(375200)	5381900	(1125600)	7.63	
4	1502700	(2735000)	751350	(1367500)	1743650	(375200)	7125550	(1500800)	7.38	
5	1452300	(2735000)	726150	(1367500)	1718450	(375200)	8844000	(1876000)	7.14	
6	1402000	(2735000)	701000	(1367500)	1693300	(375200)	10537300	(2251200)	6.89	
7	1351700	(2735000)	675850	(1367500)	1668150	(375200)	12205450	(2626400)	6.64	
8	1301300	(2735000)	650650	(1367500)	1642950	(375200)	13848400	(3001600)	6.39	
9	1251000	(2735000)	625500	(1367500)	1617800	(375200)	15466200	(3376800)	6.15	
10	1200700	(2735000)	600350	(1367500)	1592650	(375200)	17058850	(3752000)	5.90	
11	1747500	(1505400)	873750	(752700)	873750	(752700)	17932600	(4504700)	8.63	
12	1697200	(1505400)	848600	(752700)	848600	(752700)	18781200	(5257400)	8.39	
13	1646800	(1505400)	823400	(752700)	823400	(752700)	19604600	(6010100)	8.14	
14	1596500	(1505400)	798250	(752700)	798250	(752700)	20402850	(6762800)	7.89	
15	1546200	(1505400)	773100	(752700)	773100	(752700)	21175950	(7515500)	7.64	
16	1290900	(1217200)	645450	(608600)	645450	(608600)	21821400	(8124100)	6.41	
17	1240600	(1217200)	620300	(608600)	620300	(608600)	22441700	(8732700)	6.16	
18	1190300	(1217200)	595150	(608600)	595150	(608600)	23036850	(9341300)	5.91	
19	1139900	(1217200)	569950	(608600)	569950	(608600)	23606800	(9949900)	5.66	
20	1089600	(1217200)	544800	(608600)	544800	(608600)	24151600	(10558500)	5.41	
21	777400	(772900)	388700	(386450)	388700	(386450)	24540300	(10944950)	3.88	
22	727000	(772900)	363500	(386450)	363500	(386450)	24903800	(11331400)	3.63	
23	676700	(772900)	338350	(386450)	338350	(386450)	25242150	(11717850)	3.38	
24	626400	(772900)	313200	(386450)	313200	(386450)	25555350	(12104300)	3.13	
25	576000	(772900)	288000	(386450)	288000	(386450)	25843350	(12490750)	2.88	
26	525700	(772900)	262850	(386450)	262850	(386450)	26106200	(12877200)	2.63	
27	475300	(772900)	237650	(386450)	237650	(386450)	26343850	(13263650)	2.37	
28	425000	(772900)	212500	(386450)	212500	(386450)	26556350	(13650100)	2.12	
29	374700	(772900)	187350	(386450)	187350	(386450)	26743700	(14036550)	1.87	
30	324300	(772900)	162150	(386450)	162150	(386450)	26905850	(14423000)	1.62	
TOT	33965700	(48692000)	16932850	(24346000)	26905850	(14423000)			AVG= 5.66	

Table A-173

MAGNESIA SCHEME C, NONREGULATED CO. ECONOMICS, 500 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 18111000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 12.5%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	94700	5469100	7209600	(1740500)	5469100	8.00	757600
2	7000	94700	5469100	7087400	(1618300)	5469100	8.00	757600
3	7000	94700	5469100	6965200	(1496100)	5469100	8.00	757600
4	7000	94700	5469100	6843000	(1373900)	5469100	8.00	757600
5	7000	94700	5469100	6720900	(1251800)	5469100	8.00	757600
6	7000	94700	5469100	6598700	(1129600)	5469100	8.00	757600
7	7000	94700	5469100	6476500	(1007400)	5469100	8.00	757600
8	7000	94700	5469100	6354300	(885200)	5469100	8.00	757600
9	7000	94700	5469100	6232100	(763000)	5469100	8.00	757600
10	7000	94700	5469100	6110000	(640900)	5469100	8.00	757600
11	5000	67600	2897400	5381100	(2483700)	2897400	5.00	338000
12	5000	67600	2897400	5258900	(2361500)	2897400	5.00	338000
13	5000	67600	2897400	5136700	(2239300)	2897400	5.00	338000
14	5000	67600	2897400	5014500	(2117100)	2897400	5.00	338000
15	5000	67600	2897400	4892400	(1995000)	2897400	5.00	338000
16	3500	47300	2292500	4280700	(1988200)	2292500	5.00	236500
17	3500	47300	2292500	4158500	(1866000)	2292500	5.00	236500
18	3500	47300	2292500	4036300	(1743800)	2292500	5.00	236500
19	3500	47300	2292500	3914200	(1621700)	2292500	5.00	236500
20	3500	47300	2292500	3792000	(1499500)	2292500	5.00	236500
21	1500	20300	1394600	2926100	(1531500)	1394600	5.00	101500
22	1500	20300	1394600	2803900	(1409300)	1394600	5.00	101500
23	1500	20300	1394600	2681700	(1287100)	1394600	5.00	101500
24	1500	20300	1394600	2559600	(1165000)	1394600	5.00	101500
25	1500	20300	1394600	2437400	(1042800)	1394600	5.00	101500
26	1500	20300	1394600	2315200	(920600)	1394600	5.00	101500
27	1500	20300	1394600	2193000	(798400)	1394600	5.00	101500
28	1500	20300	1394600	2070800	(676200)	1394600	5.00	101500
29	1500	20300	1394600	1948700	(554100)	1394600	5.00	101500
30	1500	20300	1394600	1826500	(431900)	1394600	5.00	101500
TOT	127500	1724500	94586500	136225900	(41639400)	94586500		11463500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 6.2
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	2498100	(4711500)	1249050	(2355750)	3060150	(544650)	3060150	(544650)	6.73	
2	2375900	(4711500)	1187950	(2355750)	2999050	(544650)	6059200	(1089300)	6.40	
3	2253700	(4711500)	1126850	(2355750)	2937950	(544650)	8997150	(1633950)	6.07	
4	2131500	(4711500)	1065750	(2355750)	2876850	(544650)	11874000	(2178600)	5.74	
5	2009400	(4711500)	1004700	(2355750)	2815800	(544650)	14689800	(2723250)	5.41	
6	1887200	(4711500)	943600	(2355750)	2754700	(544650)	17444500	(3267900)	5.08	
7	1765000	(4711500)	882500	(2355750)	2693600	(544650)	20138100	(3812550)	4.75	
8	1642800	(4711500)	821400	(2355750)	2632500	(544650)	22770600	(4357200)	4.43	
9	1520600	(4711500)	760300	(2355750)	2571400	(544650)	25342000	(4901850)	4.10	
10	1398500	(4711500)	699250	(2355750)	2510350	(544650)	27852350	(5446500)	3.77	
11	2821700	(2559400)	1410850	(1279700)	1410850	(1279700)	29263200	(6726200)	7.64	
12	2699500	(2559400)	1349750	(1279700)	1349750	(1279700)	30612950	(8005900)	7.31	
13	2577300	(2559400)	1288650	(1279700)	1288650	(1279700)	31901600	(9285600)	6.98	
14	2455100	(2559400)	1227550	(1279700)	1227550	(1279700)	33129150	(10565300)	6.65	
15	2333000	(2559400)	1166500	(1279700)	1166500	(1279700)	34295650	(11845000)	6.32	
16	2224700	(2056000)	1112350	(1028000)	1112350	(1028000)	35408000	(12873000)	6.05	
17	2102500	(2056000)	1051250	(1028000)	1051250	(1028000)	36459250	(13901000)	5.72	
18	1980300	(2056000)	990150	(1028000)	990150	(1028000)	37449400	(14929000)	5.39	
19	1858200	(2056000)	929100	(1028000)	929100	(1028000)	38378500	(15957000)	5.06	
20	1736000	(2056000)	868000	(1028000)	868000	(1028000)	39246500	(16985000)	4.72	
21	1633000	(1293100)	816500	(646550)	816500	(646550)	40063000	(17631550)	4.47	
22	1510800	(1293100)	755400	(646550)	755400	(646550)	40818400	(18278100)	4.14	
23	1388600	(1293100)	694300	(646550)	694300	(646550)	41512700	(18924650)	3.80	
24	1266500	(1293100)	633250	(646550)	633250	(646550)	42145950	(19571200)	3.47	
25	1144300	(1293100)	572150	(646550)	572150	(646550)	42718100	(20217750)	3.13	
26	1022100	(1293100)	511050	(646550)	511050	(646550)	43229150	(20864300)	2.80	
27	899900	(1293100)	449950	(646550)	449950	(646550)	43679100	(21510850)	2.47	
28	777700	(1293100)	388850	(646550)	388850	(646550)	44067950	(22157400)	2.13	
29	655600	(1293100)	327800	(646550)	327800	(646550)	44395750	(22803950)	1.80	
30	533400	(1293100)	266700	(646550)	266700	(646550)	44662450	(23450500)	1.46	
TOT	53102900	(83123000)	26551450	(41561500)	44662450	(23450500)			AVG= 4.85	

Table A-174

MAGNESIA SCHEME C, NONREGULATED CO. ECONOMICS, 500 MW, NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 18111000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 19.2%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of high-cost limestone proc..

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	94700	5469100	9115900	(3646800)	5469100	8.00	757600
2	7000	94700	5469100	9016300	(3547200)	5469100	8.00	757600
3	7000	94700	5469100	8916700	(3447600)	5469100	8.00	757600
4	7000	94700	5469100	8817100	(3348000)	5469100	8.00	757600
5	7000	94700	5469100	8717600	(3248500)	5469100	8.00	757600
6	7000	94700	5469100	8618000	(3148900)	5469100	8.00	757600
7	7000	94700	5469100	8518400	(3049300)	5469100	8.00	757600
8	7000	94700	5469100	8418800	(2949700)	5469100	8.00	757600
9	7000	94700	5469100	8319200	(2850100)	5469100	8.00	757600
10	7000	94700	5469100	8219600	(2750500)	5469100	8.00	757600
11	5000	67600	2897400	6719600	(3822200)	2897400	5.00	338000
12	5000	67600	2897400	6620000	(3722600)	2897400	5.00	338000
13	5000	67600	2897400	6520400	(3623000)	2897400	5.00	338000
14	5000	67600	2897400	6420800	(3523400)	2897400	5.00	338000
15	5000	67600	2897400	6321200	(3423800)	2897400	5.00	338000
16	3500	47300	2292500	5139500	(2847000)	2292500	5.00	236500
17	3500	47300	2292500	5039900	(2747400)	2292500	5.00	236500
18	3500	47300	2292500	4940300	(2647800)	2292500	5.00	236500
19	3500	47300	2292500	4840700	(2548200)	2292500	5.00	236500
20	3500	47300	2292500	4741100	(2448600)	2292500	5.00	236500
21	1500	20300	1394600	3114300	(1719700)	1394600	5.00	101500
22	1500	20300	1394600	3014700	(1620100)	1394600	5.00	101500
23	1500	20300	1394600	2915100	(1520500)	1394600	5.00	101500
24	1500	20300	1394600	2815500	(1420900)	1394600	5.00	101500
25	1500	20300	1394600	2715900	(1321300)	1394600	5.00	101500
26	1500	20300	1394600	2616400	(1221900)	1394600	5.00	101500
27	1500	20300	1394600	2516800	(1122200)	1394600	5.00	101500
28	1500	20300	1394600	2417200	(1022600)	1394600	5.00	101500
29	1500	20300	1394600	2317600	(923000)	1394600	5.00	101500
30	1500	20300	1394600	2218000	(823400)	1394600	5.00	101500
TOT	127500	1724500	94586500	170642600	(76056100)	94586500		11463500

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 4.6
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	4404400	(4711500)	2202200	(2355750)	4013300	(544650)	4013300	(544650)	11.86	
2	4304800	(4711500)	2152400	(2355750)	3963500	(544650)	7976800	(1089300)	11.60	
3	4205200	(4711500)	2102600	(2355750)	3913700	(544650)	11890500	(1633950)	11.33	
4	4105600	(4711500)	2052800	(2355750)	3863900	(544650)	15754400	(2178600)	11.06	
5	4006100	(4711500)	2003050	(2355750)	3814150	(544650)	19568550	(2723250)	10.79	
6	3906500	(4711500)	1953250	(2355750)	3764350	(544650)	23332900	(3267900)	10.52	
7	3806900	(4711500)	1903450	(2355750)	3714550	(544650)	27047450	(3812550)	10.26	
8	3707300	(4711500)	1853650	(2355750)	3664750	(544650)	30712200	(4357200)	9.99	
9	3607700	(4711500)	1803850	(2355750)	3614950	(544650)	34327150	(4901850)	9.72	
10	3508100	(4711500)	1754050	(2355750)	3565150	(544650)	37892300	(5446500)	9.45	
11	4160200	(2559400)	2080100	(1279700)	2080100	(1279700)	39972400	(6726200)	11.27	
12	4060600	(2559400)	2030300	(1279700)	2030300	(1279700)	42002700	(8005900)	11.00	
13	3961000	(2559400)	1980500	(1279700)	1980500	(1279700)	43983200	(9285600)	10.73	
14	3861400	(2559400)	1930700	(1279700)	1930700	(1279700)	45913900	(10565300)	10.46	
15	3761800	(2559400)	1880900	(1279700)	1880900	(1279700)	47794800	(11845000)	10.19	
16	3083500	(2056000)	1541750	(1028000)	1541750	(1028000)	49336550	(12873000)	8.39	
17	2983900	(2056000)	1491950	(1028000)	1491950	(1028000)	50828500	(13901000)	8.12	
18	2884300	(2056000)	1442150	(1028000)	1442150	(1028000)	52270650	(14929000)	7.85	
19	2784700	(2056000)	1392350	(1028000)	1392350	(1028000)	53663000	(15957000)	7.58	
20	2685100	(2056000)	1342550	(1028000)	1342550	(1028000)	55005550	(16985000)	7.31	
21	1821200	(1293100)	910600	(646550)	910600	(646550)	55916150	(17631550)	4.99	
22	1721600	(1293100)	860800	(646550)	860800	(646550)	56776950	(18278100)	4.72	
23	1622000	(1293100)	811000	(646550)	811000	(646550)	57587950	(18924650)	4.44	
24	1522400	(1293100)	761200	(646550)	761200	(646550)	58349150	(19571200)	4.17	
25	1422800	(1293100)	711400	(646550)	711400	(646550)	59060550	(20217750)	3.90	
26	1323300	(1293100)	661650	(646550)	661650	(646550)	59722200	(20864300)	3.63	
27	1223700	(1293100)	611850	(646550)	611850	(646550)	60334050	(21510850)	3.35	
28	1124100	(1293100)	562050	(646550)	562050	(646550)	60896100	(22157400)	3.08	
29	1024500	(1293100)	512250	(646550)	512250	(646550)	61408350	(22803950)	2.81	
30	924900	(1293100)	462450	(646550)	462450	(646550)	61870800	(23450500)	2.53	
TOT	87519600	(63123000)	43759800	(41561500)	61870800	(23453500)			AVG= 7.99	

Table A-175

MAGNESIA SCHEME C, NONREGULATED CO. ECONOMICS, 1000 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 27540000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 13.6%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	183000	8245100	11082800	(2837700)	8245100	8.00	1464000
2	7000	183000	8245100	10892700	(2647600)	8245100	8.00	1464000
3	7000	183000	8245100	10702700	(2457600)	8245100	8.00	1464000
4	7000	183000	8245100	10512600	(2267500)	8245100	8.00	1464000
5	7000	183000	8245100	10322500	(2077400)	8245100	8.00	1464000
6	7000	183000	8245100	10132500	(1887400)	8245100	8.00	1464000
7	7000	183000	8245100	9942400	(1697300)	8245100	8.00	1464000
8	7000	183000	8245100	9752300	(1507200)	8245100	8.00	1464000
9	7000	183000	8245100	9562200	(1317100)	8245100	8.00	1464000
10	7000	183000	8245100	9372200	(1127100)	8245100	8.00	1464000
11	5000	130700	4307500	8236300	(3928800)	4307500	5.00	653500
12	5000	130700	4307500	8046200	(3738700)	4307500	5.00	653500
13	5000	130700	4307500	7856200	(3548700)	4307500	5.00	653500
14	5000	130700	4307500	7666100	(3358600)	4307500	5.00	653500
15	5000	130700	4307500	7476000	(3168500)	4307500	5.00	653500
16	3500	91500	3375900	6530600	(3154700)	3375900	5.00	457500
17	3500	91500	3375900	6340600	(2964700)	3375900	5.00	457500
18	3500	91500	3375900	6150500	(2774600)	3375900	5.00	457500
19	3500	91500	3375900	5960400	(2584500)	3375900	5.00	457500
20	3500	91500	3375900	5770400	(2394500)	3375900	5.00	457500
21	1500	39200	2019300	4451700	(2432400)	2019300	5.00	196000
22	1500	39200	2019300	4261600	(2242300)	2019300	5.00	196000
23	1500	39200	2019300	4071600	(2052300)	2019300	5.00	196000
24	1500	39200	2019300	3881500	(1862200)	2019300	5.00	196000
25	1500	39200	2019300	3691400	(1672100)	2019300	5.00	196000
26	1500	39200	2019300	3501300	(1482000)	2019300	5.00	196000
27	1500	39200	2019300	3311300	(1292000)	2019300	5.00	196000
28	1500	39200	2019300	3121200	(1101900)	2019300	5.00	196000
29	1500	39200	2019300	2931100	(911800)	2019300	5.00	196000
30	1500	39200	2019300	2741100	(721800)	2019300	5.00	196000
TOT	127500	3333000	141061000	208272000	(67211000)	141061000		22155000

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 5.9
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	4301700	(6781100)	2150850	(3390550)	4904850	(636550)	4904850	(636550)	7.62	
2	4111600	(6781100)	2055800	(3390550)	4809800	(636550)	9714650	(1273100)	7.29	
3	3921600	(6781100)	1960800	(3390550)	4714800	(636550)	14429450	(1909650)	6.95	
4	3731500	(6781100)	1865750	(3390550)	4619750	(636550)	19049200	(2546200)	6.61	
5	3541400	(6781100)	1770700	(3390550)	4524700	(636550)	23573900	(3182750)	6.28	
6	3351400	(6781100)	1675700	(3390550)	4429700	(636550)	28003600	(3819300)	5.94	
7	3161300	(6781100)	1580650	(3390550)	4334650	(636550)	32338250	(4455850)	5.60	
8	2971200	(6781100)	1485600	(3390550)	4239600	(636550)	36577850	(5092400)	5.26	
9	2781100	(6781100)	1390550	(3390550)	4144550	(636550)	40722400	(5728950)	4.93	
10	2591100	(6781100)	1295550	(3390550)	4049550	(636550)	44771950	(6365500)	4.59	
11	4582300	(3654000)	2291150	(1827000)	2291150	(1827000)	47063100	(8192500)	8.17	
12	4392200	(3654000)	2196100	(1827000)	2196100	(1827000)	49259200	(10019500)	7.83	
13	4202200	(3654000)	2101100	(1827000)	2101100	(1827000)	51360300	(11846500)	7.49	
14	4012100	(3654000)	2006050	(1827000)	2006050	(1827000)	53366350	(13673500)	7.15	
15	3822000	(3654000)	1911000	(1827000)	1911000	(1827000)	55277350	(15500500)	6.81	
16	3612200	(2918400)	1806100	(1459200)	1806100	(1459200)	57083450	(16959700)	6.47	
17	3422200	(2918400)	1711100	(1459200)	1711100	(1459200)	58794550	(18418900)	6.13	
18	3232100	(2918400)	1616050	(1459200)	1616050	(1459200)	60410600	(19878100)	5.79	
19	3042000	(2918400)	1521000	(1459200)	1521000	(1459200)	61931600	(21337300)	5.45	
20	2852000	(2918400)	1426000	(1459200)	1426000	(1459200)	63357600	(22796500)	5.11	
21	2628400	(1823300)	1314200	(911650)	1314200	(911650)	64671800	(23708150)	4.74	
22	2438300	(1823300)	1219150	(911650)	1219150	(911650)	65890950	(24619800)	4.39	
23	2248300	(1823300)	1124150	(911650)	1124150	(911650)	67015100	(25531450)	4.05	
24	2058200	(1823300)	1029100	(911650)	1029100	(911650)	68044200	(26443100)	3.71	
25	1868100	(1823300)	934050	(911650)	934050	(911650)	68978250	(27354750)	3.37	
26	1678000	(1823300)	839000	(911650)	839000	(911650)	69817250	(28266400)	3.02	
27	1488000	(1823300)	744000	(911650)	744000	(911650)	70561250	(29178050)	2.68	
28	1297900	(1823300)	648950	(911650)	648950	(911650)	71210200	(30089700)	2.34	
29	1107800	(1823300)	553900	(911650)	553900	(911650)	71764100	(31001350)	2.00	
30	917800	(1823300)	458900	(911650)	458900	(911650)	72223000	(31913000)	1.65	
TOT	89366000	(118906000)	44683000	(59453000)	72223000	(31913000)			AVG= 5.37	

Table A-176

MAGNESIA SCHEME C, NONREGULATED CO. ECONOMICS, 1000 MW. NEW COAL FIRED POWER PLANT, 3.5 % S IN FUEL, 98% H2SO4 PRODUCTION.

FIXED INVESTMENT = $ 27540000
OVERALL INTEREST RATE OF RETURN WITH PAYMENT = 22.8%
OVERALL INTEREST RATE OF RETURN WITHOUT PAYMENT = NEG

Payment equivalent to projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	TOTAL MFG. COST, $/YEAR	ALTERNATIVE NONRECOVERY WET-LIMESTONE PROCESS COST AS PAYMENT TO CHEMICAL COMPANY FOR AIR POLLUTION CONTROL, $/YEAR	NET MFG. COST, $/YEAR WITH PAYMENT	NET MFG. COST, $/YEAR WITHOUT PAYMENT	NET REVENUE, $/TON 100% H2SO4	TOTAL NET SALES REVENUE, $/YEAR
1	7000	183000	8245100	15208800	(6963700)	8245100	8.00	1464000
2	7000	183000	8245100	15053700	(6808600)	8245100	8.00	1464000
3	7000	183000	8245100	14898600	(6653500)	8245100	8.00	1464000
4	7000	183000	8245100	14743500	(6498400)	8245100	8.00	1464000
5	7000	183000	8245100	14588400	(6343300)	8245100	8.00	1464000
6	7000	183000	8245100	14433200	(6188100)	8245100	8.00	1464000
7	7000	183000	8245100	14278100	(6033000)	8245100	8.00	1464000
8	7000	183000	8245100	14123000	(5877900)	8245100	8.00	1464000
9	7000	183000	8245100	13967900	(5722800)	8245100	8.00	1464000
10	7000	183000	8245100	13812800	(5567700)	8245100	8.00	1464000
11	5000	130700	4307500	11154900	(6847400)	4307500	5.00	653500
12	5000	130700	4307500	10999800	(6692300)	4307500	5.00	653500
13	5000	130700	4307500	10844700	(6537200)	4307500	5.00	653500
14	5000	130700	4307500	10689600	(6382100)	4307500	5.00	653500
15	5000	130700	4307500	10534500	(6227000)	4307500	5.00	653500
16	3500	91500	3375900	8458700	(5082800)	3375900	5.00	457500
17	3500	91500	3375900	8303600	(4927700)	3375900	5.00	457500
18	3500	91500	3375900	8148500	(4772600)	3375900	5.00	457500
19	3500	91500	3375900	7993400	(4617500)	3375900	5.00	457500
20	3500	91500	3375900	7838300	(4462400)	3375900	5.00	457500
21	1500	39200	2019300	5007900	(2988600)	2019300	5.00	196000
22	1500	39200	2019300	4852800	(2833500)	2019300	5.00	196000
23	1500	39200	2019300	4697700	(2678400)	2019300	5.00	196000
24	1500	39200	2019300	4542500	(2523200)	2019300	5.00	196000
25	1500	39200	2019300	4387400	(2368100)	2019300	5.00	196000
26	1500	39200	2019300	4232300	(2213000)	2019300	5.00	196000
27	1500	39200	2019300	4077200	(2057900)	2019300	5.00	196000
28	1500	39200	2019300	3922100	(1902800)	2019300	5.00	196000
29	1500	39200	2019300	3767000	(1747700)	2019300	5.00	196000
30	1500	39200	2019300	3611900	(1592600)	2019300	5.00	196000
TOT	127500	3333000	141061000	283172800	(142111800)	141061000		22155000

YEARS REQUIRED FOR PAYOUT WITH PAYMENT: 4.0
NO PAYOUT WITHOUT PAYMENT

YEARS AFTER POWER UNIT START	GROSS INCOME, $/YEAR WITH PAYMENT	GROSS INCOME, $/YEAR WITHOUT PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITH PAYMENT	NET INCOME AFTER TAXES, $/YEAR WITHOUT PAYMENT	CASH FLOW, $/YEAR WITH PAYMENT	CASH FLOW, $/YEAR WITHOUT PAYMENT	CUMULATIVE CASH FLOW, $ WITH PAYMENT	CUMULATIVE CASH FLOW, $ WITHOUT PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITH PAYMENT	ANNUAL RETURN ON INITIAL INVESTMENT, % WITHOUT PAYMENT
1	8427700	(6781100)	4213850	(3390550)	6967850	(636550)	6967850	(636550)	14.93	
2	8272600	(6781100)	4136300	(3390550)	6890300	(636550)	13858150	(1273100)	14.66	
3	8117500	(6781100)	4058750	(3390550)	6812750	(636550)	20670900	(1909650)	14.38	
4	7962400	(6781100)	3981200	(3390550)	6735200	(636550)	27406100	(2546200)	14.11	
5	7807300	(6781100)	3903650	(3390550)	6657650	(636550)	34063750	(3182750)	13.83	
6	7652100	(6781100)	3826050	(3390550)	6580050	(636550)	40643800	(3819300)	13.56	
7	7497000	(6781100)	3748500	(3390550)	6502500	(636550)	47146300	(4455850)	13.28	
8	7341900	(6781100)	3670950	(3390550)	6424950	(636550)	53571250	(5092400)	13.01	
9	7186800	(6781100)	3593400	(3390550)	6347400	(636550)	59918650	(5728950)	12.74	
10	7031700	(6781100)	3515850	(3390550)	6269850	(636550)	66188500	(6365500)	12.46	
11	7500900	(3654000)	3750450	(1827000)	3750450	(1827000)	69938950	(8192500)	13.37	
12	7345800	(3654000)	3672900	(1827000)	3672900	(1827000)	73611850	(10019500)	13.09	
13	7190700	(3654000)	3595350	(1827000)	3595350	(1827000)	77207200	(11846500)	12.82	
14	7035600	(3654000)	3517800	(1827000)	3517800	(1827000)	80725000	(13673500)	12.54	
15	6880500	(3654000)	3440250	(1827000)	3440250	(1827000)	84165250	(15500500)	12.26	
16	5540300	(2918400)	2770150	(1459200)	2770150	(1459200)	86935400	(16959700)	9.92	
17	5385200	(2918400)	2692600	(1459200)	2692600	(1459200)	89628000	(18418900)	9.64	
18	5230100	(2918400)	2615050	(1459200)	2615050	(1459200)	92243050	(19878100)	9.36	
19	5075000	(2918400)	2537500	(1459200)	2537500	(1459200)	94780550	(21337300)	9.09	
20	4919900	(2918400)	2459950	(1459200)	2459950	(1459200)	97240500	(22796500)	8.81	
21	3184600	(1823300)	1592300	(911650)	1592300	(911650)	98832800	(23708150)	5.74	
22	3029500	(1823300)	1514750	(911650)	1514750	(911650)	100347550	(24619800)	5.46	
23	2874400	(1823300)	1437200	(911650)	1437200	(911650)	101784750	(25531450)	5.18	
24	2719200	(1823300)	1359600	(911650)	1359600	(911650)	103144350	(26443100)	4.90	
25	2564100	(1823300)	1282050	(911650)	1282050	(911650)	104426400	(27354750)	4.62	
26	2409000	(1823300)	1204500	(911650)	1204500	(911650)	105630900	(28266400)	4.34	
27	2253900	(1823300)	1126950	(911650)	1126950	(911650)	106757850	(29178050)	4.06	
28	2098800	(1823300)	1049400	(911650)	1049400	(911650)	107807250	(30089700)	3.78	
29	1943700	(1823300)	971850	(911650)	971850	(911650)	108779100	(31001350)	3.50	
30	1788600	(1823300)	894300	(911650)	894300	(911650)	109673400	(31913000)	3.22	
TOT	164266800	(118906000)	82133400	(59453000)	109673400	(31913000)			AVG= 9.87	

Table A-177

MAGNESIA SCHEME D, REGULATED PORTION COOPERATIVE ECONOMICS, SCRUBBING-DRYING, 200 MW NEW COAL FIRED UNIT, 3.5% S, MGSO3 PROD.

Computation basis: cost of recycle MgO–$25/ton FIXED INVESTMENT: $ 7671000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR MAGNESIUM SULFITE	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON MAGNESIUM SULFITE	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	56200	3791500	0.0	0	3791500	3791500	3825400	33900	33900
2	7000	56200	3738300	0.0	0	3738300	7529800	3761700	23400	57300
3	7000	56200	3685100	0.0	0	3685100	11214900	3698000	12900	70200
4	7000	56200	3631900	0.0	0	3631900	14846800	3634200	2300	72500
5	7000	56200	3578700	0.0	0	3578700	18425500	3570500	(8200)	64300
6	7000	56200	3525500	0.0	0	3525500	21951000	3506800	(18700)	45600
7	7000	56200	3472400	0.0	0	3472400	25423400	3443000	(29400)	16200
8	7000	56200	3419200	0.0	0	3419200	28842600	3379300	(39900)	(23700)
9	7000	56200	3366000	0.0	0	3366000	32208600	3315600	(50400)	(74100)
10	7000	56200	3312800	0.0	0	3312800	35521400	3251900	(60900)	(135000)
11	5000	40200	2810600	0.0	0	2810600	38332000	2868100	57500	(77500)
12	5000	40200	2757400	0.0	0	2757400	41089400	2804400	47000	(30500)
13	5000	40200	2704200	0.0	0	2704200	43793600	2740700	36500	6000
14	5000	40200	2651100	0.0	0	2651100	46444700	2676900	25800	31800
15	5000	40200	2597900	0.0	0	2597900	49042600	2613200	15300	47100
16	3500	28100	2192900	0.0	0	2192900	51235500	2288900	96000	143100
17	3500	28100	2139700	0.0	0	2139700	53375200	2225100	85400	228500
18	3500	28100	2086500	0.0	0	2086500	55461700	2161400	74900	303400
19	3500	28100	2033300	0.0	0	2033300	57495000	2097700	64400	367800
20	3500	26100	1980100	0.0	0	1980100	59475100	2033900	53800	421600
21	1500	12100	1418100	0.0	0	1418100	60893200	1567700	149600	571200
22	1500	12100	1364900	0.0	0	1364900	62258100	1504000	139100	710300
23	1500	12100	1311700	0.0	0	1311700	63569800	1440200	128500	838800
24	1500	12100	1258500	0.0	0	1258500	64828300	1376500	118000	956800
25	1500	12100	1205300	0.0	0	1205300	66033600	1312800	107500	1064300
26	1500	12100	1152100	0.0	0	1152100	67185700	1249100	97000	1161300
27	1500	12100	1098900	0.0	0	1098900	68284600	1185300	86400	1247700
28	1500	12100	1045800	0.0	0	1045800	69330400	1121600	75800	1323500
29	1500	12100	992600	0.0	0	992600	70323000	1057900	65300	1388800
30	1500	12100	939400	0.0	0	939400	71262400	994100	54700	1443500
TOT	127500	1024500	71262400		0	71262400		72705900	1443500	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						7.29		7.44		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						2.79		2.85		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						29063400		29257300	193900	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						2.97		2.99		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						1.14		1.15		

Table A-178

MAGNESIA SCHEME D, REGULATED PORTION COOPERATIVE ECONOMICS, SCRUBBING-DRYING, 200 MW NEW COAL FIRED UNIT, 3.5% S, MGSO3 PROD.

Computation basis: cost of recycle MgO–$55/ton FIXED INVESTMENT: $ 7671000

Includes comparison with projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR MAGNESIUM SULFITE	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON MAGNESIUM SULFITE	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	56200	4499500	0.0	0	4499500	4499500	4388700	(110800)	(110800)
2	7000	56200	4446300	0.0	0	4446300	8945800	4338300	(108000)	(218800)
3	7000	56200	4393100	0.0	0	4393100	13338900	4288000	(105100)	(323900)
4	7000	56200	4339900	0.0	0	4339900	17678800	4237700	(102200)	(426100)
5	7000	56200	4286700	0.0	0	4286700	21965500	4187300	(99400)	(525500)
6	7000	56200	4233500	0.0	0	4233500	26199000	4137000	(96500)	(622000)
7	7000	56200	4180400	0.0	0	4180400	30379400	4086700	(93700)	(715700)
8	7000	56200	4127200	0.0	0	4127200	34506600	4036300	(90900)	(806600)
9	7000	56200	4074000	0.0	0	4074000	38580600	3986000	(88000)	(894600)
10	7000	56200	4020800	0.0	0	4020800	42601400	3935700	(85100)	(979700)
11	5000	40200	3316300	0.0	0	3316300	45917700	3252900	(63400)	(1043100)
12	5000	40200	3263100	0.0	0	3263100	49180800	3202600	(60500)	(1103600)
13	5000	40200	3209900	0.0	0	3209900	52390700	3152200	(57700)	(1161300)
14	5000	40200	3156800	0.0	0	3156800	55547500	3101900	(54900)	(1216200)
15	5000	40200	3103600	0.0	0	3103600	58651100	3051600	(52000)	(1268200)
16	3500	28100	2546900	0.0	0	2546900	61198000	2508100	(38800)	(1307000)
17	3500	28100	2493700	0.0	0	2493700	63691700	2457800	(35900)	(1342900)
18	3500	28100	2440500	0.0	0	2440500	66132200	2407500	(33000)	(1375900)
19	3500	28100	2387300	0.0	0	2387300	68519500	2357100	(30200)	(1406100)
20	3500	28100	2334100	0.0	0	2334100	70853600	2306800	(27300)	(1433400)
21	1500	12100	1569800	0.0	0	1569800	72423400	1550300	(19500)	(1452900)
22	1500	12100	1516600	0.0	0	1516600	73940000	1499900	(16700)	(1469600)
23	1500	12100	1463400	0.0	0	1463400	75403400	1449600	(13800)	(1483400)
24	1500	12100	1410200	0.0	0	1410200	76813600	1399300	(10900)	(1494300)
25	1500	12100	1357000	0.0	0	1357000	78170600	1348900	(8100)	(1502400)
26	1500	12100	1303800	0.0	0	1303800	79474400	1298600	(5200)	(1507600)
27	1500	12100	1250600	0.0	0	1250600	80725000	1248200	(2400)	(1510000)
28	1500	12100	1197500	0.0	0	1197500	81922500	1197900	400	(1509600)
29	1500	12100	1144300	0.0	0	1144300	83066800	1147600	3300	(1506300)
30	1500	12100	1091100	0.0	0	1091100	84157900	1097200	6100	(1500200)
TOT	127500	1024500	84157900		0	84157900		82657700	(1500200)	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						8.61		8.46		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						3.30		3.24		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						34612600		33873300	(739300)	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						3.54		3.47		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						1.36		1.33		

Table A-179

MAGNESIA SCHEME D, NONREGULATED PORTION COOPERATIVE ECONOMICS, MGO-H2SO4 PROD. EQUIV. TO 1 200 MW COAL FIRED UNIT, 3.5% S IN COAL.

FIXED INVESTMENT = $ 5017000
OVERALL INTEREST RATE OF RETURN = NEG
NO PAYOUT

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR		TOTAL MFG. COST, $/YEAR	NET REVENUE, $/TON		TOTAL NET SALES REVENUE, $/YEAR	GROSS INCOME, $/YEAR	NET INCOME AFTER TAXES, $/YEAR	CASH FLOW, $/YEAR	CUMULATIVE CASH FLOW, $	ANNUAL RETURN ON INITIAL INVESTMENT, %
	100% H2SO4	RECYCLE MGO		100% H2SO4	RECYCLE MGO						
1	45200	23600	1651300	12.00	25.00	1132400	(518900)	(259450)	242250	242250	
2	45200	23600	1651300	12.00	25.00	1132400	(518900)	(259450)	242250	484500	
3	45200	23600	1651300	12.00	25.00	1132400	(518900)	(259450)	242250	726750	
4	45200	23600	1651300	12.00	25.00	1132400	(518900)	(259450)	242250	969000	
5	45200	23600	1651300	12.00	25.00	1132400	(518900)	(259450)	242250	1211250	
6	45200	23600	1651300	12.00	25.00	1132400	(518900)	(259450)	242250	1453500	
7	45200	23600	1651300	12.00	25.00	1132400	(518900)	(259450)	242250	1695750	
8	45200	23600	1651300	12.00	25.00	1132400	(518900)	(259450)	242250	1938000	
9	45200	23600	1651300	12.00	25.00	1132400	(518900)	(259450)	242250	2180250	
10	45200	23600	1651300	12.00	25.00	1132400	(518900)	(259450)	242250	2422500	
TOT	452000	236000	16513000			11324000	(5189000)	(2594500)	2422500		AVG=

Table A-180

MAGNESIA SCHEME D, NONREGULATED PORTION COOPERATIVE ECONOMICS, MGO-H2SO4 PROD. EQUIV. TO 1 200 MW COAL FIRED UNIT, 3.5% S IN COAL.

FIXED INVESTMENT = $ 5017000
OVERALL INTEREST RATE OF RETURN = 3.3%
YEARS REQUIRED FOR PAYOUT = 8.4

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	PRODUCT RATE, EQUIVALENT TONS/YEAR RECYCLE MGO	TOTAL MFG. COST, $/YEAR	NET REVENUE, $/TON 100% H2SO4	NET REVENUE, $/TON RECYCLE MGO	TOTAL NET SALES REVENUE, $/YEAR	GROSS INCOME, $/YEAR	NET INCOME AFTER TAXES, $/YEAR	CASH FLOW, $/YEAR	CUMULATIVE CASH FLOW, $	ANNUAL RETURN ON INITIAL INVESTMENT, %
1	45200	23600	1651300	12.00	55.00	1840400	189100	94550	596250	596250	1.83
2	45200	23600	1651300	12.00	55.00	1840400	189100	94550	596250	1192500	1.83
3	45200	23600	1651300	12.00	55.00	1840400	189100	94550	596250	1788750	1.83
4	45200	23600	1651300	12.00	55.00	1840400	189100	94550	596250	2385000	1.83
5	45200	23600	1651300	12.00	55.00	1840400	189100	94550	596250	2981250	1.83
6	45200	23600	1651300	12.00	55.00	1840400	189100	94550	596250	3577500	1.83
7	45200	23600	1651300	12.00	55.00	1840400	189100	94550	596250	4173750	1.83
8	45200	23600	1651300	12.00	55.00	1840400	189100	94550	596250	4770000	1.83
9	45200	23600	1651300	12.00	55.00	1840400	189100	94550	596250	5366250	1.83
10	45200	23600	1651300	12.00	55.00	1840400	189100	94550	596250	5962500	1.83
TOT	452000	236000	16513000			18404000	1891000	945500	5962500	AVG=	1.83

Table A-181

MAGNESIA SCHEME D, NONREGULATED PORTION COOPERATIVE ECONOMICS, MGO-H2SO4 PROD. EQUIV. TO 5 200 MW COAL FIRED UNIT, 3.5% S

FIXED INVESTMENT = $ 12354000
OVERALL INTEREST RATE OF RETURN = 8.2%
YEARS REQUIRED FOR PAYOUT = 6.6

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR		TOTAL MFG. COST, $/YEAR	NET REVENUE, $/TON		TOTAL NET SALES REVENUE, $/YEAR	GROSS INCOME, $/YEAR	NET INCOME AFTER TAXES, $/YEAR	CASH FLOW, $/YEAR	CUMULATIVE CASH FLOW, $	ANNUAL RETURN ON INITIAL INVESTMENT, %
	100% H2SO4	RECYCLE MGO		100% H2SO4	RECYCLE MGO						
1	226000	118000	4414600	12.00	25.00	5662000	1247400	623700	1859100	1859100	4.88
2	226000	118000	4414600	12.00	25.00	5662000	1247400	623700	1859100	3718200	4.88
3	226000	118000	4414600	12.00	25.00	5662000	1247400	623700	1859100	5577300	4.88
4	226000	118000	4414600	12.00	25.00	5662000	1247400	623700	1859100	7436400	4.88
5	226000	118000	4414600	12.00	25.00	5662000	1247400	623700	1859100	9295500	4.88
6	226000	118000	4414600	12.00	25.00	5662000	1247400	623700	1859100	11154600	4.88
7	226000	118000	4414600	12.00	25.00	5662000	1247400	623700	1859100	13013700	4.88
8	226000	118000	4414600	12.00	25.00	5662000	1247400	623700	1859100	14872800	4.88
9	226000	118000	4414600	12.00	25.00	5662000	1247400	623700	1859100	16731900	4.88
10	226000	118000	4414600	12.00	25.00	5662000	1247400	623700	1859100	18591000	4.88
TOT	2260000	1180000	44146000			56620000	12474000	6237000	18591000	AVG=	4.88

Table A-182

MAGNESIA SCHEME D, NONREGULATED PORTION COOPERATIVE ECONOMICS, MGO-H2SO4 PROD. EQUIV. TO 5 200 MW COAL FIRED UNIT, 3.5% S

FIXED INVESTMENT = $ 12354000
OVERALL INTEREST RATE OF RETURN = 26.6%
YEARS REQUIRED FOR PAYOUT = 3.4

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR		TOTAL MFG. COST, $/YEAR	NET REVENUE, $/TON		TOTAL NET SALES REVENUE, $/YEAR	GROSS INCOME, $/YEAR	NET INCOME AFTER TAXES, $/YEAR	CASH FLOW, $/YEAR	CUMULATIVE CASH FLOW, $	ANNUAL RETURN ON INITIAL INVESTMENT, %
	100% H2SO4	RECYCLE MGO		100% H2SO4	RECYCLE MGO						
1	226000	118000	4414600	12.00	55.00	9202000	4787400	2393700	3629100	3629100	18.72
2	226000	118000	4414600	12.00	55.00	9202000	4787400	2393700	3629100	7258200	18.72
3	226000	118000	4414600	12.00	55.00	9202000	4787400	2393700	3629100	10887300	18.72
4	226000	118000	4414600	12.00	55.00	9202000	4787400	2393700	3629100	14516400	18.72
5	226000	118000	4414600	12.00	55.00	9202000	4787400	2393700	3629100	18145500	18.72
6	226000	118000	4414600	12.00	55.00	9202000	4787400	2393700	3629100	21774600	18.72
7	226000	118000	4414600	12.00	55.00	9202000	4787400	2393700	3629100	25403700	18.72
8	226000	118000	4414600	12.00	55.00	9202000	4787400	2393700	3629100	29032800	18.72
9	226000	118000	4414600	12.00	55.00	9202000	4787400	2393700	3629100	32661900	18.72
10	226000	118000	4414600	12.00	55.00	9202000	4787400	2393700	3629100	36291000	18.72
TOT	2260000	1180000	44146000			92020000	47874000	23937000	36291000	AVG=	18.72

Table A-183

MAGNESIA SCHEME D, NONREGULATED PORTION COOPERATIVE ECONOMICS, MGO-H2SO4 PROD. EQUIV. TO 10 200 MW COAL FIRED UNIT, 3.5% S

FIXED INVESTMENT = $ 19534000
OVERALL INTEREST RATE OF RETURN = 14.0%
YEARS REQUIRED FOR PAYOUT = 5.2

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR		TOTAL MFG. COST, $/YEAR	NET REVENUE, $/TON		TOTAL NET SALES REVENUE, $/YEAR	GROSS INCOME, $/YEAR	NET INCOME AFTER TAXES, $/YEAR	CASH FLOW, $/YEAR	CUMULATIVE CASH FLOW, $	ANNUAL RETURN ON INITIAL INVESTMENT, %
	100% H2SO4	RECYCLE MGO		100% H2SO4	RECYCLE MGO						
1	452000	236000	7734100	12.00	25.00	11324000	3589900	1794950	3748350	3748350	8.82
2	452000	236000	7734100	12.00	25.00	11324000	3589900	1794950	3748350	7496700	8.82
3	452000	236000	7734100	12.00	25.00	11324000	3589900	1794950	3748350	11245050	8.82
4	452000	236000	7734100	12.00	25.00	11324000	3589900	1794950	3748350	14993400	8.82
5	452000	236000	7734100	12.00	25.00	11324000	3589900	1794950	3748350	18741750	8.82
6	452000	236000	7734100	12.00	25.00	11324000	3589900	1794950	3748350	22490100	8.82
7	452000	236000	7734100	12.00	25.00	11324000	3589900	1794950	3748350	26238450	8.82
8	452000	236000	7734100	12.00	25.00	11324000	3589900	1794950	3748350	29986800	8.82
9	452000	236000	7734100	12.00	25.00	11324000	3589900	1794950	3748350	33735150	8.82
10	452000	236000	7734100	12.00	25.00	11324000	3589900	1794950	3748350	37483500	8.82
TOT	4520000	2360000	77341000			113240000	35899000	17949500	37483500	AVG=	8.82

Table A-184

MAGNESIA SCHEME D, NONREGULATED PORTION COOPERATIVE ECONOMICS, MGO-H2SO4 PROD. EQUIV. TO 10 200 MW COAL FIRED UNIT, 3.5% S

FIXED INVESTMENT = $ 19534000
OVERALL INTEREST RATE OF RETURN = 35.5%
YEARS REQUIRED FOR PAYOUT = 2.7

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR		TOTAL MFG. COST, $/YEAR	NET REVENUE, $/TON		TOTAL NET SALES REVENUE, $/YEAR	GROSS INCOME, $/YEAR	NET INCOME AFTER TAXES, $/YEAR	CASH FLOW, $/YEAR	CUMULATIVE CASH FLOW, $	ANNUAL RETURN ON INITIAL INVESTMENT, %
	100% H2SO4	RECYCLE MGO		100% H2SO4	RECYCLE MGO						
1	452000	236000	7734100	12.00	55.00	18404000	10669900	5334950	7288350	7288350	26.23
2	452000	236000	7734100	12.00	55.00	18404000	10669900	5334950	7288350	14576700	26.23
3	452000	236000	7734100	12.00	55.00	18404000	10669900	5334950	7288350	21865050	26.23
4	452000	236000	7734100	12.00	55.00	18404000	10669900	5334950	7288350	29153400	26.23
5	452000	236000	7734100	12.00	55.00	18404000	10669900	5334950	7288350	36441750	26.23
6	452000	236000	7734100	12.00	55.00	18404000	10669900	5334950	7288350	43730100	26.23
7	452000	236000	7734100	12.00	55.00	18404000	10669900	5334950	7288350	51018450	26.23
8	452000	236000	7734100	12.00	55.00	18404000	10669900	5334950	7288350	58306800	26.23
9	452000	236000	7734100	12.00	55.00	18404000	10669900	5334950	7288350	65595150	26.23
10	452000	236000	7734100	12.00	55.00	18404000	10669900	5334950	7288350	72883500	26.23
TOT	4520000	2360000	77341000			184040000	106699000	53349500	72883500		AVG= 26.23

Table A-185

MAGNESIA SCHEME D, NONREGULATED PORTION COOPERATIVE ECONOMICS, MGO-H_2SO_4 PROD. EQUIV. TO 15 200 MW COAL FIRED UNIT, 3.5% S

FIXED INVESTMENT = $ 26096000
OVERALL INTEREST RATE OF RETURN = 17.2%
YEARS REQUIRED FOR PAYOUT = 4.6

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR		TOTAL MFG. COST, $/YEAR	NET REVENUE, $/TON		TOTAL NET SALES REVENUE, $/YEAR	GROSS INCOME, $/YEAR	NET INCOME AFTER TAXES, $/YEAR	CASH FLOW, $/YEAR	CUMULATIVE CASH FLOW, $	ANNUAL RETURN ON INITIAL INVESTMENT, %
	100% H_2SO_4	RECYCLE MGO		100% H_2SO_4	RECYCLE MGO						
1	678000	354000	10923800	12.00	25.00	16986000	6062200	3031100	5640700	5640700	11.12
2	678000	354000	10923800	12.00	25.00	16986000	6062200	3031100	5640700	11281400	11.12
3	678000	354000	10923800	12.00	25.00	16986000	6062200	3031100	5640700	16922100	11.12
4	678000	354000	10923800	12.00	25.00	16986000	6062200	3031100	5640700	22562800	11.12
5	678000	354000	10923800	12.00	25.00	16986000	6062200	3031100	5640700	28203500	11.12
6	678000	354000	10923800	12.00	25.00	16986000	6062200	3031100	5640700	33844200	11.12
7	678000	354000	10923800	12.00	25.00	16986000	6062200	3031100	5640700	39484900	11.12
8	678000	354000	10923800	12.00	25.00	16986000	6062200	3031100	5640700	45125600	11.12
9	678000	354000	10923800	12.00	25.00	16986000	6062200	3031100	5640700	50766300	11.12
10	678000	354000	10923800	12.00	25.00	16986000	6062200	3031100	5640700	56407000	11.12
TOT	6780000	3540000	109238000			169860000	60622000	30311000	56407000	AVG=	11.12

Table A-186

MAGNESIA SCHEME D, NONREGULATED PORTICN COOPERATIVE ECONOMICS, MGO-H2SO4 PROD. EQUIV. TO 15 200 MW COAL FIRED UNIT, 3.5% S

FIXED INVESTMENT = $ 26096000
OVERALL INTEREST RATE OF RETURN = 40.6%
YEARS REQUIRED FOR PAYOUT = 2.4

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR		TOTAL MFG. COST, $/YEAR	NET REVENUE, $/TON		TOTAL NET SALES REVENUE, $/YEAR	GROSS INCOME, $/YEAR	NET INCOME AFTER TAXES, $/YEAR	CASH FLOW, $/YEAR	CUMULATIVE CASH FLOW, $	ANNUAL RETURN ON INITIAL INVESTMENT, %
	100% H2SO4	RECYCLE MGO		100% H2SO4	RECYCLE MGO						
1	678000	354000	10923800	12.00	55.00	27606000	16682200	8341100	10950700	10950700	30.59
2	678000	354000	10923800	12.00	55.00	27606000	16682200	8341100	10950700	21901400	30.59
3	678000	354000	10923800	12.00	55.00	27606000	16682200	8341100	10950700	32852100	30.59
4	678000	354000	10923800	12.00	55.00	27606000	16682200	8341100	10950700	43802800	30.59
5	678000	354000	10923800	12.00	55.00	27606000	16682200	8341100	10950700	54753500	30.59
6	678000	354000	10923800	12.00	55.00	27606000	16682200	8341100	10950700	65704200	30.59
7	676000	354000	10923800	12.00	55.00	27606000	16682200	8341100	10950700	76654900	30.59
8	678000	354000	10923800	12.00	55.00	27606000	16682200	8341100	10950700	87605600	30.59
9	678000	354000	10923800	12.00	55.00	27606000	16682200	8341100	10950700	98556300	30.59
10	678000	356000	10923800	12.00	55.00	27606000	16682200	8341100	10950700	109507000	30.59
TOT	6780000	3540000	109238000			276060000	166822000	83411000	109507000		AVG= 30.59

Table A-187

MAGNESIA SCHEME D, REGULATED PORTION COOPERATIVE ECONOMICS, SCRUBBING-DRYING, 500 MW NEW COAL FIRED UNIT, 3.5% S, MGSO3 PROD.

Computation basis: cost of recycle MgO–$15/ton FIXED INVESTMENT: $ 14844000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR MAGNESIUM SULFITE	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON MAGNESIUM SULFITE	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	133600	7049700	0.0	0	7049700	7049700	7209600	159900	159900
2	7000	133600	6946700	0.0	0	6946700	13996400	7087400	140700	300600
3	7000	133600	6843800	0.0	0	6843800	20840200	6965200	121400	422000
4	7000	133600	6740900	0.0	0	6740900	27581100	6843000	102100	524100
5	7000	133600	6638000	0.0	0	6638000	34219100	6720900	82900	607000
6	7000	133600	6535100	0.0	0	6535100	40754200	6598700	63600	670600
7	7000	133600	6432100	0.0	0	6432100	47186300	6476500	44400	715000
8	7000	133600	6329200	0.0	0	6329200	53515500	6354300	25100	740100
9	7000	133600	6226300	0.0	0	6226300	59741800	6232100	5800	745900
10	7000	133600	6123600	0.0	0	6123600	65865200	6110000	(13600)	732500
11	5000	95400	5214300	0.0	0	5214300	71079500	5381100	166800	899300
12	5000	95400	5111300	0.0	0	5111300	76190800	5258900	147600	1046900
13	5000	95400	5008400	0.0	0	5008400	81199200	5136700	128300	1175200
14	5000	95400	4905500	0.0	0	4905500	86104700	5014500	109000	1284200
15	5000	95400	4802600	0.0	0	4802600	90907300	4892400	89800	1374000
16	3500	66800	4069000	0.0	0	4069000	94976300	4280700	211700	1585700
17	3500	66800	3966100	0.0	0	3966100	98942400	4158500	192400	1778100
18	3500	66800	3863100	0.0	0	3863100	102805500	4036300	173200	1951300
19	3500	66800	3760200	0.0	0	3760200	106565700	3914200	154000	2105300
20	3500	66800	3657300	0.0	0	3657300	110223000	3792000	134700	2240000
21	1500	28600	2645200	0.0	0	2645200	112868200	2926100	280900	2520900
22	1500	28600	2542300	0.0	0	2542300	115410500	2803900	261600	2782500
23	1500	28600	2439300	0.0	0	2439300	117849800	2681700	242400	3024900
24	1500	28600	2336400	0.0	0	2336400	120186200	2559600	223200	3248100
25	1500	28600	2233500	0.0	0	2233500	122419700	2437400	203900	3452000
26	1500	28600	2130600	0.0	0	2130600	124550300	2315200	184600	3636600
27	1500	28600	2027700	0.0	0	2027700	126578000	2193000	165300	3801900
28	1500	28600	1924800	0.0	0	1924800	128502800	2070800	146000	3947900
29	1500	28600	1821800	0.0	0	1821800	130324600	1948700	126900	4074800
30	1500	28600	1718900	0.0	0	1718900	132043500	1826500	107600	4182400
TOT	127500	2433000	132043500		0	132043500		136225900	4182400	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						5.52		5.70		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						2.07		2.14		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						53898800		54984900	1086100	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						2.25		2.30		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.85		0.86		

Table A-188

MAGNESIA SCHEME D, REGULATED PORTION COOPERATIVE ECONOMICS, SCRUBBING-DRYING, 500 MW NEW COAL FIRED UNIT, 3.5% S, MGSO3 PROD.

Computation basis: cost of recycle MgO–$55/ton FIXED INVESTMENT: $ 14844000

Includes comparison with projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR MAGNESIUM SULFITE	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON MAGNESIUM SULFITE	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	133600	9289700	0.0	0	9289700	9289700	9115900	(173800)	(173800)
2	7000	133600	9186700	0.0	0	9186700	18476400	9016300	(170400)	(344200)
3	7000	133600	9083800	0.0	0	9083800	27560200	8916700	(167100)	(511300)
4	7000	133600	8980900	0.0	0	8980900	36541100	8817100	(163800)	(675100)
5	7000	133600	8878000	0.0	0	8878000	45419100	8717600	(160400)	(835500)
6	7000	133600	8775100	0.0	0	8775100	54194200	8618000	(157100)	(992600)
7	7000	133600	8672100	0.0	0	8672100	62866300	8518400	(153700)	(1146300)
8	7000	133600	8569200	0.0	0	8569200	71435500	8418800	(150400)	(1296700)
9	7000	133600	8466300	0.0	0	8466300	79901800	8319200	(147100)	(1443800)
10	7000	133600	8363400	0.0	0	8363400	88265200	8219600	(143800)	(1587600)
11	5000	95400	6814300	0.0	0	6814300	95079500	6719600	(94700)	(1682300)
12	5000	95400	6711300	0.0	0	6711300	101790800	6620000	(91300)	(1773600)
13	5000	95400	6608400	0.0	0	6608400	108399200	6520400	(88000)	(1861600)
14	5000	95400	6505500	0.0	0	6505500	114904700	6420800	(84700)	(1946300)
15	5000	95400	6402600	0.0	0	6402600	121307300	6321200	(81400)	(2027700)
16	3500	66800	5189000	0.0	0	5189000	126496300	5139500	(49500)	(2077200)
17	3500	66800	5086100	0.0	0	5086100	131582400	5039900	(46200)	(2123400)
18	3500	66800	4983100	0.0	0	4983100	136565500	4940300	(42800)	(2166200)
19	3500	66800	4880200	0.0	0	4880200	141445700	4840700	(39500)	(2205700)
20	3500	66800	4777300	0.0	0	4777300	146223000	4741100	(36200)	(2241900)
21	1500	28600	3125200	0.0	0	3125200	149348200	3114300	(10900)	(2252800)
22	1500	28600	3022300	0.0	0	3022300	152370500	3014700	(7600)	(2260400)
23	1500	28600	2919300	0.0	0	2919300	155289800	2915100	(4200)	(2264600)
24	1500	28600	2816400	0.0	0	2816400	158106200	2815500	(900)	(2265500)
25	1500	28600	2713500	0.0	0	2713500	160819700	2715900	2400	(2263100)
26	1500	28600	2610600	0.0	0	2610600	163430300	2616400	5800	(2257300)
27	1500	28600	2507700	0.0	0	2507700	165938000	2516800	9100	(2248200)
28	1500	28600	2404800	0.0	0	2404800	168342800	2417200	12400	(2235800)
29	1500	28600	2301800	0.0	0	2301800	170644600	2317600	15800	(2220000)
30	1500	28600	2198900	0.0	0	2198900	172843500	2218000	19100	(2200900)
TOT	127500	2433000	172843500		0	172843500		170642600	(2200900)	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						7.23		7.14		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						2.71		2.68		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						71455800		70296800	(1159000)	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						2.99		2.94		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						1.12		1.10		

Table A-189

MAGNESIA SCHEME D, NONREGULATED PORTION COOPERATIVE ECONOMICS, MGO-H2SO4 PROD. EQUIV. TO 1 500 MW COAL FIRED UNIT, 3.5% S

FIXED INVESTMENT = $ 8294000
OVERALL INTEREST RATE OF RETURN = NEG
NO PAYOUT

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR		TOTAL MFG. COST, $/YEAR	NET REVENUE, $/TON		TOTAL NET SALES REVENUE, $/YEAR	GROSS INCOME, $/YEAR	NET INCOME AFTER TAXES, $/YEAR	CASH FLOW, $/YEAR	CUMULATIVE CASH FLOW, $	ANNUAL RETURN ON INITIAL INVESTMENT, %
	100% H2SO4	RECYCLE MGO		100% H2SO4	RECYCLE MGO						
1	110400	56000	2838500	12.00	15.00	2164800	(673700)	(336850)	492550	492550	
2	110400	56000	2838500	12.00	15.00	2164800	(673700)	(336850)	492550	985100	
3	110400	56000	2838500	12.00	15.00	2164800	(673700)	(336850)	492550	1477650	
4	110400	56000	2838500	12.00	15.00	2164800	(673700)	(336850)	492550	1970200	
5	110400	56000	2838500	12.00	15.00	2164800	(673700)	(336850)	492550	2462750	
6	110400	56000	2838500	12.00	15.00	2164800	(673700)	(336850)	492550	2955300	
7	110400	56000	2838500	12.00	15.00	2164800	(673700)	(336850)	492550	3447850	
8	110400	56000	2838500	12.00	15.00	2164800	(673700)	(336850)	492550	3940400	
9	110400	56000	2838500	12.00	15.00	2164800	(673700)	(336850)	492550	4432950	
10	110400	56000	2838500	12.00	15.00	2164800	(673700)	(336850)	492550	4925500	
TOT	1104000	560000	28385000			21648000	(6737000)	(3368500)	4925500		AVG=

Table A-190

MAGNESIA SCHEME D, NONREGULATED PORTION COOPERATIVE ECONOMICS, MGO-H2SO4 PROD. EQUIV. TO 1 500 MW COAL FIRED UNIT, 3.5% S

FIXED INVESTMENT = $ 8294000
OVERALL INTEREST RATE OF RETURN = 14.4%
YEARS REQUIRED FOR PAYOUT = 5.1

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR		TOTAL MFG. COST, $/YEAR	NET REVENUE, $/TON		TOTAL NET SALES REVENUE, $/YEAR	GROSS INCOME, $/YEAR	NET INCOME AFTER TAXES, $/YEAR	CASH FLOW, $/YEAR	CUMULATIVE CASH FLOW, $	ANNUAL RETURN ON INITIAL INVESTMENT, %
	100% H2SO4	RECYCLE MGO		100% H2SO4	RECYCLE MGO						
1	110400	56000	2838500	12.00	55.00	4404800	1566300	783150	1612550	1612550	9.15
2	110400	56000	2838500	12.00	55.00	4404800	1566300	783150	1612550	3225100	9.15
3	110400	56000	2838500	12.00	55.00	4404800	1566300	783150	1612550	4837650	9.15
4	110400	56000	2838500	12.00	55.00	4404800	1566300	783150	1612550	6450200	9.15
5	110400	56000	2838500	12.00	55.00	4404800	1566300	783150	1612550	8062750	9.15
6	110400	56000	2838500	12.00	55.00	4404800	1566300	783150	1612550	9675300	9.15
7	110400	56000	2838500	12.00	55.00	4404800	1566300	783150	1612550	11287850	9.15
8	110400	56000	2838500	12.00	55.00	4404800	1566300	783150	1612550	12900400	9.15
9	110400	56000	2838500	12.00	55.00	4404800	1566300	783150	1612550	14512950	9.15
10	110400	56000	2838500	12.00	55.00	4404800	1566300	783150	1612550	16125500	9.15
TOT	1104000	560000	28385000			44048000	15663000	7831500	16125500	AVG=	9.15

Table A-191

MAGNESIA SCHEME D, NONREGULATED PORTION COOPERATIVE ECONOMICS, MGO-H2SO4 PROD. EQUIV. TO 2 500 MW COAL FIRED UNITS, 3.5% S

FIXED INVESTMENT = $ 12354000
OVERALL INTEREST RATE OF RETURN = 0.3%
YEARS REQUIRED FOR PAYOUT = 9.9

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR		TOTAL MFG. COST, $/YEAR	NET REVENUE, $/TON		TOTAL NET SALES REVENUE, $/YEAR	GROSS INCOME, $/YEAR	NET INCOME AFTER TAXES, $/YEAR	CASH FLOW, $/YEAR	CUMULATIVE CASH FLOW, $	ANNUAL RETURN ON INITIAL INVESTMENT, %
	100% H2SO4	RECYCLE MGO		100% H2SO4	RECYCLE MGO						
1	220800	112000	4292300	12.00	15.00	4329600	37300	18650	1254050	1254050	0.15
2	220800	112000	4292300	12.00	15.00	4329600	37300	18650	1254050	2508100	0.15
3	220800	112000	4292300	12.00	15.00	4329600	37300	18650	1254050	3762150	0.15
4	220800	112000	4292300	12.00	15.00	4329600	37300	18650	1254050	5016200	0.15
5	220800	112000	4292300	12.00	15.00	4329600	37300	18650	1254050	6270250	0.15
6	220800	112000	4292300	12.00	15.00	4329600	37300	18650	1254050	7524300	0.15
7	220800	112000	4292300	12.00	15.00	4329600	37300	18650	1254050	8778350	0.15
8	220800	112000	4292300	12.00	15.00	4329600	37300	18650	1254050	10032400	0.15
9	220800	112000	4292300	12.00	15.00	4329600	37300	18650	1254050	11286450	0.15
10	220800	112000	4292300	12.00	15.00	4329600	37300	18650	1254050	12540500	0.15
TOT	2208000	1120000	42923000			43296000	373000	186500	12540500	AVG=	0.15

Table A-192

MAGNESIA SCHEME D, NONREGULATED PORTION COOPERATIVE ECONOMICS, MGO-H2SO4 PROD. EQUIV. TO 2 500 MW COAL FIRED UNITS, 3.5% S

FIXED INVESTMENT = $ 12354000
OVERALL INTEREST RATE OF RETURN = 25.3%
YEARS REQUIRED FOR PAYOUT = 3.5

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR		TOTAL MFG. COST, $/YEAR	NET REVENUE, $/TON		TOTAL NET SALES REVENUE, $/YEAR	GROSS INCOME, $/YEAR	NET INCOME AFTER TAXES, $/YEAR	CASH FLOW, $/YEAR	CUMULATIVE CASH FLOW, $	ANNUAL RETURN ON INITIAL INVESTMENT, %
	100% H2SO4	RECYCLE MGO		100% H2SO4	RECYCLE MGO						
1	220800	112000	4292300	12.00	55.00	8809600	4517300	2258650	3494050	3494050	17.69
2	220800	112000	4292300	12.00	55.00	8809600	4517300	2258650	3494050	6988100	17.69
3	220800	112000	4292300	12.00	55.00	8809600	4517300	2258650	3494050	10482150	17.69
4	220800	112000	4292300	12.00	55.00	8809600	4517300	2258650	3494050	13976200	17.69
5	220800	112000	4292300	12.00	55.00	8809600	4517300	2258650	3494050	17470250	17.69
6	220800	112000	4292300	12.00	55.00	8809600	4517300	2258650	3494050	20964300	17.69
7	220800	112000	4292300	12.00	55.00	8809600	4517300	2258650	3494050	24458350	17.69
8	220800	112000	4292300	12.00	55.00	8809600	4517300	2258650	3494050	27952400	17.69
9	220800	112000	4292300	12.00	55.00	8809600	4517300	2258650	3494050	31446450	17.69
10	220800	112000	4292300	12.00	55.00	8809600	4517300	2258650	3494050	34940500	17.69
TOT	2208000	1120000	42923000			88096000	45173000	22586500	34940500	AVG=	17.69

Table A-193

MAGNESIA SCHEME D, NONREGULATED PORTION COOPERATIVE ECONOMICS, MGO-H2SO4 PROD. EQUIV. TO 4 500 MW COAL FIRED UNITS, 3.5% S

FIXED INVESTMENT = $ 19534000
OVERALL INTEREST RATE OF RETURN = 5.1%
YEARS REQUIRED FOR PAYOUT = 7.7

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	RECYCLE MGO	TOTAL MFG. COST, $/YEAR	NET REVENUE, $/TON 100% H2SO4	RECYCLE MGO	TOTAL NET SALES REVENUE, $/YEAR	GROSS INCOME, $/YEAR	NET INCOME AFTER TAXES, $/YEAR	CASH FLOW, $/YEAR	CUMULATIVE CASH FLOW, $	ANNUAL RETURN ON INITIAL INVESTMENT, %
1	441600	224000	7473200	12.00	15.00	8659200	1186000	593000	2546400	2546400	2.92
2	441600	224000	7473200	12.00	15.00	8659200	1186000	593000	2546400	5092800	2.92
3	441600	224000	7473200	12.00	15.00	8659200	1186000	593000	2546400	7639200	2.92
4	441600	224000	7473200	12.00	15.00	8659200	1186000	593000	2546400	10185600	2.92
5	441600	224000	7473200	12.00	15.00	8659200	1186000	593000	2546400	12732000	2.92
6	441600	224000	7473200	12.00	15.00	8659200	1186000	593000	2546400	15278400	2.92
7	441600	224000	7473200	12.00	15.00	8659200	1186000	593000	2546400	17824800	2.92
8	441600	224000	7473200	12.00	15.00	8659200	1186000	593000	2546400	20371200	2.92
9	441600	224000	7473200	12.00	15.00	8659200	1186000	593000	2546400	22917600	2.92
10	441600	224000	7473200	12.00	15.00	8659200	1186000	593000	2546400	25464000	2.92
TOT	4416000	2240000	74732000			86592000	11860000	5930000	25464000	AVG=	2.92

Table A-194

MAGNESIA SCHEME D, NONREGULATED PORTION COOPERATIVE ECONOMICS, MGO-H2SO4 PROD. EQUIV. TO 4 500 MW COAL FIRED UNITS, 3.5% S

FIXED INVESTMENT = $ 19534000
OVERALL INTEREST RATE OF RETURN = 34.1%
YEARS REQUIRED FOR PAYOUT = 2.8

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR		TOTAL MFG. COST, $/YEAR	NET REVENUE, $/TON		TOTAL NET SALES REVENUE, $/YEAR	GROSS INCOME, $/YEAR	NET INCOME AFTER TAXES, $/YEAR	CASH FLOW, $/YEAR	CUMULATIVE CASH FLOW, $	ANNUAL RETURN ON INITIAL INVESTMENT, %
	100% H2SO4	RECYCLE MGO		100% H2SO4	RECYCLE MGO						
1	441600	224000	7473200	12.00	55.00	17619200	10146000	5073000	7026400	7026400	24.99
2	441600	224000	7473200	12.00	55.00	17619200	10146000	5073000	7026400	14052800	24.99
3	441600	224000	7473200	12.00	55.00	17619200	10146000	5073000	7026400	21079200	24.99
4	441600	224000	7473200	12.00	55.00	17619200	10146000	5073000	7026400	28105600	24.99
5	441600	224000	7473200	12.00	55.00	17619200	10146000	5073000	7026400	35132000	24.99
6	441600	224000	7473200	12.00	55.00	17619200	10146000	5073000	7026400	42158400	24.99
7	441600	224000	7473200	12.00	55.00	17619200	10146000	5073000	7026400	49184800	24.99
8	441600	224000	7473200	12.00	55.00	17619200	10146000	5073000	7026400	56211200	24.99
9	441600	224000	7473200	12.00	55.00	17619200	10146000	5073000	7026400	63237600	24.99
10	441600	224000	7473200	12.00	55.00	17619200	10146000	5073000	7026400	70264000	24.99
TOT	4416000	2240000	74732000			176192000	101460000	50730000	70264000		AVG= 24.99

Table A-195

MAGNESIA SCHEME D, NONREGULATED PORTION COOPERATIVE ECONOMICS, MGO-H2SO4 PROD. EQUIV. TO 6 500 MW COAL FIRED UNITS, 3.5% S

FIXED INVESTMENT = $ 26096000
OVERALL INTEREST RATE OF RETURN = 8.7%
YEARS REQUIRED FOR PAYOUT = 6.5

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR		TOTAL MFG. COST, $/YEAR	NET REVENUE, $/TON		TOTAL NET SALES REVENUE, $/YEAR	GROSS INCOME, $/YEAR	NET INCOME AFTER TAXES, $/YEAR	CASH FLOW, $/YEAR	CUMULATIVE CASH FLOW, $	ANNUAL RETURN ON INITIAL INVESTMENT, %
	100% H2SO4	RECYCLE MGO		100% H2SO4	RECYCLE MGO						
1	662400	336000	10190700	12.00	15.00	12988800	2798100	1399050	4008650	4008650	5.15
2	662400	336000	10190700	12.00	15.00	12988800	2798100	1399050	4008650	8017300	5.15
3	662400	336000	10190700	12.00	15.00	12988800	2798100	1399050	4008650	12025950	5.15
4	662400	336000	10190700	12.00	15.00	12988800	2798100	1399050	4008650	16034600	5.15
5	662400	336000	10190700	12.00	15.00	12988800	2798100	1399050	4008650	20043250	5.15
6	662400	336000	10190700	12.00	15.00	12988800	2798100	1399050	4008650	24051900	5.15
7	662400	336000	10190700	12.00	15.00	12988800	2798100	1399050	4008650	28060550	5.15
8	662400	336000	10190700	12.00	15.00	12988800	2798100	1399050	4008650	32069200	5.15
9	662400	336000	10190700	12.00	15.00	12988800	2798100	1399050	4008650	36077850	5.15
10	662400	336000	10190700	12.00	15.00	12988800	2798100	1399050	4008650	40086500	5.15
TOT	6624000	3360000	101907000			129888000	27981000	13990500	40086500	AVG=	5.15

Table A-196

MAGNESIA SCHEME D, NONREGULATED PORTION COOPERATIVE ECONOMICS, MGO-H2SO4 PROD. EQUIV. TO 6 500 MW COAL FIRED UNITS, 3.5% S

FIXED INVESTMENT = $ 26096000
OVERALL INTEREST RATE OF RETURN = 39.7%
YEARS REQUIRED FOR PAYOUT = 2.4

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR		TOTAL MFG. COST, $/YEAR	NET REVENUE, $/TON		TOTAL NET SALES REVENUE, $/YEAR	GROSS INCOME, $/YEAR	NET INCOME AFTER TAXES, $/YEAR	CASH FLOW, $/YEAR	CUMULATIVE CASH FLOW, $	ANNUAL RETURN ON INITIAL INVESTMENT, %
	100% H2SO4	RECYCLE MGO		100% H2SO4	RECYCLE MGO						
1	662400	336000	10190700	12.00	55.00	26428800	16238100	8119050	10728650	10728650	29.89
2	662400	336000	10190700	12.00	55.00	26428800	16238100	8119050	10728650	21457300	29.89
3	662400	336000	10190700	12.00	55.00	26428800	16238100	8119050	10728650	32185950	29.89
4	662400	336000	10190700	12.00	55.00	26428800	16238100	8119050	10728650	42914600	29.89
5	662400	336000	10190700	12.00	55.00	26428800	16238100	8119050	10728650	53643250	29.89
6	662400	336000	10190700	12.00	55.00	26428800	16238100	8119050	10728650	64371900	29.89
7	662400	336000	10190700	12.00	55.00	26428800	16238100	8119050	10728650	75100550	29.89
8	662400	336000	10190700	12.00	55.00	26428800	16238100	8119050	10728650	85829200	29.89
9	662400	336000	10190700	12.00	55.00	26428800	16238100	8119050	10728650	96557850	29.89
10	662400	336000	10190700	12.00	55.00	26428800	16238100	8119050	10728650	107286500	29.89
TOT	6624000	3360000	101907000			264288000	162381000	81190500	107286500		AVG= 29.89

Table A-197

MAGNESIA SCHEME D, REGULATED PORTION COOPERATIVE ECONOMICS, SCRUBBING-DRYING, 1000 MW NEW COAL FIRED UNIT, 3.5% S, MGSO3 PROD.

Computation basis: cost of recycle MgO–$10/ton

FIXED INVESTMENT: $ 22673000

Includes comparison with projected operating cost of low-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR MAGNESIUM SULFITE	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON MAGNESIUM SULFITE	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	258300	10850800	0.0	0	10850800	10850800	11082800	232000	232000
2	7000	258300	10693600	0.0	0	10693600	21544400	10892700	199100	431100
3	7000	258300	10536400	0.0	0	10536400	32080800	10702700	166300	597400
4	7000	258300	10379200	0.0	0	10379200	42460000	10512600	133400	730800
5	7000	258300	10222000	0.0	0	10222000	52682000	10322500	100500	831300
6	7000	258300	10064800	0.0	0	10064800	62746800	10132500	67700	899000
7	7000	258300	9907500	0.0	0	9907500	72654300	9942400	34900	933900
8	7000	258300	9750300	0.0	0	9750300	82404600	9752300	2000	935900
9	7000	258300	9593100	0.0	0	9593100	91997700	9562200	(30900)	905000
10	7000	258300	9435900	0.0	0	9435900	101433600	9372200	(63700)	841300
11	5000	184500	8021100	0.0	0	8021100	109454700	8236300	215200	1056500
12	5000	184500	7863900	0.0	0	7863900	117318600	8046200	182300	1238800
13	5000	184500	7706700	0.0	0	7706700	125025300	7856200	149500	1388300
14	5000	184500	7549500	0.0	0	7549500	132574800	7666100	116600	1504900
15	5000	184500	7392300	0.0	0	7392300	139967100	7476000	83700	1588600
16	3500	129100	6252700	0.0	0	6252700	146219800	6530600	277900	1866500
17	3500	129100	6095500	0.0	0	6095500	152315300	6340600	245100	2111600
18	3500	129100	5938300	0.0	0	5938300	158253600	6150500	212200	2323800
19	3500	129100	5781100	0.0	0	5781100	164034700	5960400	179300	2503100
20	3500	129100	5623900	0.0	0	5623900	169658600	5770400	146500	2649600
21	1500	55300	4053400	0.0	0	4053400	173712000	4451700	398300	3047900
22	1500	55300	3896100	0.0	0	3896100	177608100	4261600	365500	3413400
23	1500	55300	3738900	0.0	0	3738900	181347000	4071600	332700	3746100
24	1500	55300	3581700	0.0	0	3581700	184928700	3881500	299800	4045900
25	1500	55300	3424500	0.0	0	3424500	188353200	3691400	266900	4312800
26	1500	55300	3267300	0.0	0	3267300	191620500	3501300	234000	4546800
27	1500	55300	3110100	0.0	0	3110100	194730600	3311300	201200	4748000
28	1500	55300	2952900	0.0	0	2952900	197683500	3121200	168300	4916300
29	1500	55300	2795700	0.0	0	2795700	200479200	2931100	135400	5051700
30	1500	55300	2638500	0.0	0	2638500	203117700	2741100	102600	5154300
TOT	127500	4704000	203117700		0	203117700		208272000	5154300	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						4.39		4.51		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						1.59		1.63		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						82965000		84316100	1351100	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						1.80		1.82		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.65		0.66		

Table A-198

MAGNESIA SCHEME D, REGULATED PORTION COOPERATIVE ECONOMICS, SCRUBBING-DRYING, 1000 MW NEW COAL FIRED UNIT, 3.5% S, MGSO3 PROD.

Computation basis: cost of recycle MgO–$55/ton FIXED INVESTMENT: $ 22673000

Includes comparison with projected operating cost of high-cost limestone process

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	PRODUCT RATE, EQUIVALENT TONS/YEAR MAGNESIUM SULFITE	TOTAL MFG. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	NET REVENUE, $/TON MAGNESIUM SULFITE	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $	ALTERNATIVE OPERATING COST FOR NON-RECOVERY WET-LIMESTONE PROCESS INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	ANNUAL SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $	CUMULATIVE SAVINGS (LOSS) USING RECOVERY PROCESS INSTEAD OF WET-LIMESTONE SCRUBBING, $
1	7000	258300	15722700	0.0	0	15722700	15722700	15208800	(513900)	(513900)
2	7000	258300	15565500	0.0	0	15565500	31288200	15053700	(511800)	(1025700)
3	7000	258300	15408300	0.0	0	15408300	46696500	14898600	(509700)	(1535400)
4	7000	258300	15251100	0.0	0	15251100	61947600	14743500	(507600)	(2043000)
5	7000	258300	15093900	0.0	0	15093900	77041500	14588400	(505500)	(2548500)
6	7000	258300	14936700	0.0	0	14936700	91978200	14433200	(503500)	(3052000)
7	7000	258300	14779400	0.0	0	14779400	106757600	14278100	(501300)	(3553300)
8	7000	258300	14622200	0.0	0	14622200	121379800	14123000	(499200)	(4052500)
9	7000	258300	14465000	0.0	0	14465000	135844800	13967900	(497100)	(4549600)
10	7000	258300	14307800	0.0	0	14307800	150152600	13812800	(495000)	(5044600)
11	5000	184500	11501100	0.0	0	11501100	161653700	11154900	(346200)	(5390800)
12	5000	184500	11343900	0.0	0	11343900	172997600	10999800	(344100)	(5734900)
13	5000	184500	11186700	0.0	0	11186700	184184300	10844700	(342000)	(6076900)
14	5000	184500	11029500	0.0	0	11029500	195213800	10689600	(339900)	(6416800)
15	5000	184500	10872300	0.0	0	10872300	206086100	10534500	(337800)	(6754600)
16	3500	129100	8688700	0.0	0	8688700	214774800	8458700	(230000)	(6984600)
17	3500	129100	8531500	0.0	0	8531500	223306300	8303600	(227900)	(7212500)
18	3500	129100	8374300	0.0	0	8374300	231680600	8148500	(225800)	(7438300)
19	3500	129100	8217100	0.0	0	8217100	239897700	7993400	(223700)	(7662000)
20	3500	129100	8059900	0.0	0	8059900	247957600	7838300	(221600)	(7883600)
21	1500	55300	5097400	0.0	0	5097400	253055000	5007900	(89500)	(7973100)
22	1500	55300	4940100	0.0	0	4940100	257995100	4852800	(87300)	(8060400)
23	1500	55300	4782900	0.0	0	4782900	262778000	4697700	(85200)	(8145600)
24	1500	55300	4625700	0.0	0	4625700	267403700	4542500	(83200)	(8228800)
25	1500	55300	4468500	0.0	0	4468500	271872200	4387400	(81100)	(8309900)
26	1500	55300	4311300	0.0	0	4311300	276183500	4232300	(79000)	(8388900)
27	1500	55300	4154100	0.0	0	4154100	280337600	4077200	(76900)	(8465800)
28	1500	55300	3996900	0.0	0	3996900	284334500	3922100	(74800)	(8540600)
29	1500	55300	3839700	0.0	0	3839700	288174200	3767000	(72700)	(8613300)
30	1500	55300	3682500	0.0	0	3682500	291856700	3611900	(70600)	(8683900)
TOT	127500	4704000	291856700		0	291856700		283172800	(8683900)	
EQUIVALENT COST, DOLLARS PER TON OF COAL BURNED						6.31		6.13		
EQUIVALENT COST, MILLS PER KILOWATT-HOUR						2.29		2.22		
PRESENT WORTH IF DISCOUNTED AT 10.0% TO INITIAL YEAR, DOLLARS						121150900		117261000	(3889900)	
EQUIVALENT PRESENT WORTH, DOLLARS PER TON OF COAL BURNED						2.62		2.54		
EQUIVALENT PRESENT WORTH, MILLS PER KILOWATT-HOUR						0.95		0.92		

Table A-199

MAGNESIA SCHEME D, NONREGULATED PORTION COOPERATIVE ECONOMICS, MGO-H2SO4 PROD. EQUIV. TO 1 1000 MW COAL FIRED UNIT, 3.5% S

FIXED INVESTMENT = $ 12354000
OVERALL INTEREST RATE OF RETURN = NFG
NO PAYOUT

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR		TOTAL MFG. COST, $/YEAR	NET REVENUE, $/TON		TOTAL NET SALES REVENUE, $/YEAR	GROSS INCOME, $/YEAR	NET INCOME AFTER TAXES, $/YEAR	CASH FLOW, $/YEAR	CUMULATIVE CASH FLOW, $	ANNUAL RETURN ON INITIAL INVESTMENT, %
	100% H2SO4	RECYCLE MGO		100% H2SO4	RECYCLE MGO						
1	213500	108265	4187000	12.00	10.00	3644700	(542300)	(271150)	964250	964250	
2	213500	108265	4187000	12.00	10.00	3644700	(542300)	(271150)	964250	1928500	
3	213500	108265	4187000	12.00	10.00	3644700	(542300)	(271150)	964250	2892750	
4	213500	108265	4187000	12.00	10.00	3644700	(542300)	(271150)	964250	3857000	
5	213500	108265	4187000	12.00	10.00	3644700	(542300)	(271150)	964250	4821250	
6	213500	108265	4187000	12.00	10.00	3644700	(542300)	(271150)	964250	5785500	
7	213500	108265	4187000	12.00	10.00	3644700	(542300)	(271150)	964250	6749750	
8	213500	108265	4187000	12.00	10.00	3644700	(542300)	(271150)	964250	7714000	
9	213500	108265	4187000	12.00	10.00	3644700	(542300)	(271150)	964250	8678250	
10	213500	108265	4187000	12.00	10.00	3644700	(542300)	(271150)	964250	9642500	
TOT	2135000	1082650	41870000			36447000	(5423000)	(2711500)	9642500		AVG=

Table A-200

MAGNESIA SCHEME D, NONREGULATED PORTION COOPERATIVE ECONOMICS, MGO-H2SO4 PROD. EQUIV. TO 1 1000 MW COAL FIRED UNIT, 3.5% S

FIXED INVESTMENT = $ 12354000
OVERALL INTEREST RATE OF RETURN = 24.4%
YEARS REQUIRED FOR PAYOUT = 3.6

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR		TOTAL MFG. COST, $/YEAR	NET REVENUE, $/TON		TOTAL NET SALES REVENUE, $/YEAR	GROSS INCOME, $/YEAR	NET INCOME AFTER TAXES, $/YEAR	CASH FLOW, $/YEAR	CUMULATIVE CASH FLOW, $	ANNUAL RETURN ON INITIAL INVESTMENT, %
	100% H2SO4	RECYCLE MGO		100% H2SO4	RECYCLE MGO						
1	213500	108265	4187000	12.00	55.00	8516600	4329600	2164800	3400200	3400200	16.97
2	213500	108265	4187000	12.00	55.00	8516600	4329600	2164800	3400200	6800400	16.97
3	213500	108265	4187000	12.00	55.00	8516600	4329600	2164800	3400200	10200600	16.97
4	213500	108265	4187000	12.00	55.00	8516600	4329600	2164800	3400200	13600800	16.97
5	213500	108265	4187000	12.00	55.00	8516600	4329600	2164800	3400200	17001000	16.97
6	213500	108265	4187000	12.00	55.00	8516600	4329600	2164800	3400200	20401200	16.97
7	213500	108265	4187000	12.00	55.00	8516600	4329600	2164800	3400200	23801400	16.97
8	213500	108265	4187000	12.00	55.00	8516600	4329600	2164800	3400200	27201600	16.97
9	213500	108265	4187000	12.00	55.00	8516600	4329600	2164800	3400200	30601800	16.97
10	213500	108265	4187000	12.00	55.00	8516600	4329600	2164800	3400200	34002000	16.97
TOT	2135000	1082650	41870000			85166000	43296000	21648000	34002000		AVG= 16.97

Table A-201

MAGNESIA SCHEME D, NONREGULATED PORTION COOPERATIVE ECONOMICS, MGO-H2SO4 PROD. EQUIV. TO 2 1000 MW COAL FIRED UNITS, 3.5% S

FIXED INVESTMENT = \$ 19534000
OVERALL INTEREST RATE OF RETURN = 0.1%
YEARS REQUIRED FOR PAYOUT = 9.9

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR		TOTAL MFG. COST, \$/YEAR	NET REVENUE, \$/TON		TOTAL NET SALES REVENUE, \$/YEAR	GROSS INCOME, \$/YEAR	NET INCOME AFTER TAXES, \$/YEAR	CASH FLOW, \$/YEAR	CUMULATIVE CASH FLOW, \$	ANNUAL RETURN ON INITIAL INVESTMENT, %
	100% H2SO4	RECYCLE MGO		100% H2SO4	RECYCLE MGO						
1	427000	216530	7263900	12.00	10.00	7289300	25400	12700	1966100	1966100	0.06
2	427000	216530	7263900	12.00	10.00	7289300	25400	12700	1966100	3932200	0.06
3	427000	216530	7263900	12.00	10.00	7289300	25400	12700	1966100	5898300	0.06
4	427000	216530	7263900	12.00	10.00	7289300	25400	12700	1966100	7864400	0.06
5	427000	216530	7263900	12.00	10.00	7289300	25400	12700	1966100	9830500	0.06
6	427000	216530	7263900	12.00	10.00	7289300	25400	12700	1966100	11796600	0.06
7	427000	216530	7263900	12.00	10.00	7289300	25400	12700	1966100	13762700	0.06
8	427000	216530	7263900	12.00	10.00	7289300	25400	12700	1966100	15728800	0.06
9	427000	216530	7263900	12.00	10.00	7289300	25400	12700	1966100	17694900	0.06
10	427000	216530	7263900	12.00	10.00	7289300	25400	12700	1966100	19661000	0.06
TOT	4270000	2165300	72639000			72893000	254000	127000	19661000	AVG=	0.06

Table A-202

MAGNESIA SCHEME D, NONREGULATED PORTION COOPERATIVE ECONOMICS, MGO-H2SO4 PROD. EQUIV. TO 2 1000 MW COAL FIRED UNITS, 3.5% S

FIXED INVESTMENT = $ 19534000
OVERALL INTEREST RATE OF RETURN = 33.0%
YEARS REQUIRED FOR PAYOUT = 2.9

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR		TOTAL MFG. COST, $/YEAR	NET REVENUE, $/TON		TOTAL NET SALES REVENUE, $/YEAR	GROSS INCOME, $/YEAR	NET INCOME AFTER TAXES, $/YEAR	CASH FLOW, $/YEAR	CUMULATIVE CASH FLOW, $	ANNUAL RETURN ON INITIAL INVESTMENT, %
	100% H2SO4	RECYCLE MGO		100% H2SO4	RECYCLE MGO						
1	427000	216530	7263900	12.00	55.00	17033200	9769300	4884650	6838050	6838050	24.10
2	427000	216530	7263900	12.00	55.00	17033200	9769300	4884650	6838050	13676100	24.10
3	427000	216530	7263900	12.00	55.00	17033200	9769300	4884650	6838050	20514150	24.10
4	427000	216530	7263900	12.00	55.00	17033200	9769300	4884650	6838050	27352200	24.10
5	427000	216530	7263900	12.00	55.00	17033200	9769300	4884650	6838050	34190250	24.10
6	427000	216530	7263900	12.00	55.00	17033200	9769300	4884650	6838050	41028300	24.10
7	427000	216530	7263900	12.00	55.00	17033200	9769300	4884650	6838050	47866350	24.10
8	427000	216530	7263900	12.00	55.00	17033200	9769300	4884650	6838050	54704400	24.10
9	427000	216530	7263900	12.00	55.00	17033200	9769300	4884650	6838050	61542450	24.10
10	427000	216530	7263900	12.00	55.00	17033200	9769300	4884650	6838050	68380500	24.10
TOT	4270000	2165300	72639000			170332000	97693000	48846500	68380500	AVG=	24.10

Table A-203

MAGNESIA SCHEME D, NONREGULATED PORTION COOPERATIVE ECONOMICS, MGO-H2SO4 PROD. EQUIV. TO 3 1000 MW COAL FIRED UNITS, 3.5% S

FIXED INVESTMENT = $ 26096000
OVERALL INTEREST RATE OF RETURN = 3.5%
YEARS REQUIRED FOR PAYOUT = 8.3

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR		TOTAL MFG. COST, $/YEAR	NET REVENUE, $/TON		TOTAL NET SALES REVENUE, $/YEAR	GROSS INCOME, $/YEAR	NET INCOME AFTER TAXES, $/YEAR	CASH FLOW, $/YEAR	CUMULATIVE CASH FLOW, $	ANNUAL RETURN ON INITIAL INVESTMENT, %
	100% H2SO4	RECYCLE MGO		100% H2SO4	RECYCLE MGO						
1	640500	324795	9875900	12.00	10.00	10934000	1058100	529050	3138650	3138650	1.95
2	640500	324795	9875900	12.00	10.00	10934000	1058100	529050	3138650	6277300	1.95
3	640500	324795	9875900	12.00	10.00	10934000	1058100	529050	3138650	9415950	1.95
4	640500	324795	9875900	12.00	10.00	10934000	1058100	529050	3138650	12554600	1.95
5	640500	324795	9875900	12.00	10.00	10934000	1058100	529050	3138650	15693250	1.95
6	640500	324795	9875900	12.00	10.00	10934000	1058100	529050	3138650	18831900	1.95
7	640500	324795	9875900	12.00	10.00	10934000	1058100	529050	3138650	21970550	1.95
8	640500	324795	9875900	12.00	10.00	10934000	1058100	529050	3138650	25109200	1.95
9	640500	324795	9875900	12.00	10.00	10934000	1058100	529050	3138650	28247850	1.95
10	640500	324795	9875900	12.00	10.00	10934000	1058100	529050	3138650	31386500	1.95
TOT	6405000	3247950	98759000			109340000	10581000	5290500	31386500	AVG=	1.95

Table A-204

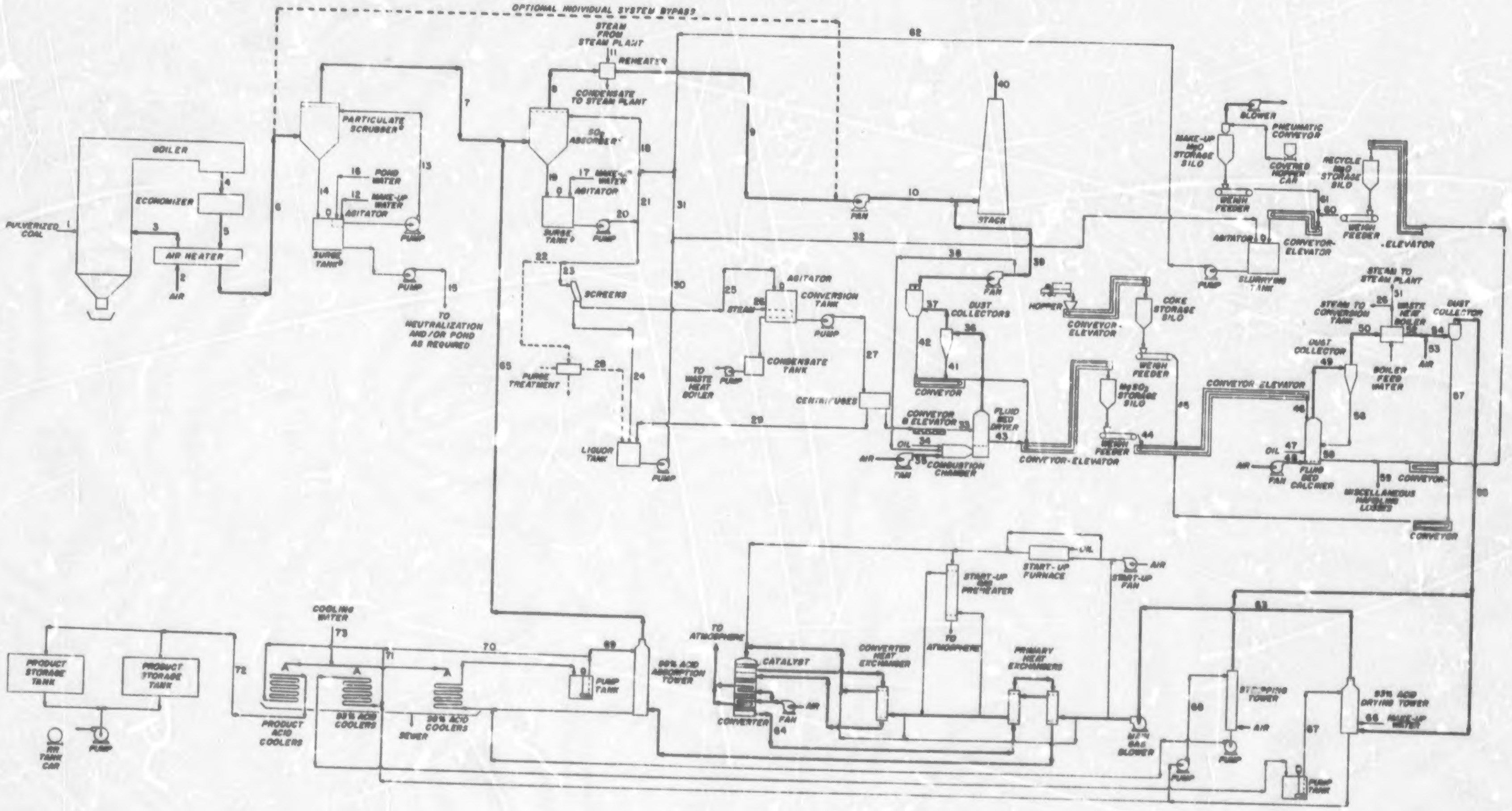
MAGNESIA SCHEME D, NONREGULATED PORTION COOPERATIVE ECONOMICS, MGO-H2SO4 PROD. EQUIV. TO 3 1000 MW COAL FIRED UNITS, 3.5% S

FIXED INVESTMENT = $ 26096000
OVERALL INTEREST RATE OF RETURN = 38.5%
YEARS REQUIRED FOR PAYOUT = 2.5

YEARS AFTER PLANT START UP	PRODUCT RATE, EQUIVALENT TONS/YEAR		TOTAL MFG. COST, $/YEAR	NET REVENUE, $/TON		TOTAL NET SALES REVENUE, $/YEAR	GROSS INCOME, $/YEAR	NET INCOME AFTER TAXES, $/YEAR	CASH FLOW, $/YEAR	CUMULATIVE CASH FLOW, $	ANNUAL RETURN ON INITIAL INVESTMENT, %
	100% H2SO4	RECYCLE MGO		100% H2SO4	RECYCLE MGO						
1	640500	324795	9875900	12.00	55.00	25549700	15673800	7836900	10446500	10446500	28.90
2	640500	324795	9875900	12.00	55.00	25549700	15673800	7836900	10446500	20893000	28.90
3	640500	324795	9875900	12.00	55.00	25549700	15673800	7836900	10446500	31339500	28.90
4	640500	324795	9875900	12.00	55.00	25549700	15673800	7836900	10446500	41786000	28.90
5	640500	324795	9875900	12.00	55.00	25549700	15673800	7836900	10446500	52232500	28.90
6	640500	324795	9875900	12.00	55.00	25549700	15673800	7836900	10446500	62679000	28.90
7	640500	324795	9875900	12.00	55.00	25549700	15673800	7836900	10446500	73125500	28.90
8	640500	324795	9875900	12.00	55.00	25549700	15673800	7836900	10446500	83572000	28.90
9	640500	324795	9875900	12.00	55.00	25549700	15673800	7836900	10446500	94018500	28.90
10	640500	324795	9875900	12.00	55.00	25549700	15673800	7836900	10446500	104465000	28.90
TOT	6405000	3247950	98759000			255497000	156738000	78369000	104465000	AVG=	28.90

APPENDIX B

Engineering Drawings


OPTIONAL INDIVIDUAL SYSTEM BYPASS
PULVERIZED COAL
BOILER
ECONOMIZER
AIR HEATER
AIR
PARTICULATE SCRUBBER○
POND WATER
MAKE-UP WATER
AGITATOR
SURGE TANK△
PUMP
TO NEUTRALIZATION AND/OR POND AS REQUIRED
STEAM FROM STEAM PLANT
REHEATER
CONDENSATE TO STEAM PLANT
SO2 ABSORBER○
MAKE-UP WATER
AGITATOR
SURGE TANK△
PUMP
SCREENS
PURGE TREATMENT
LIQUOR TANK
PUMP
STEAM
AGITATOR
CONVERSION TANK
PUMP
CONDENSATE TANK
TO WASTE HEAT BOILER
PUMP
CENTRIFUGES
FAN
STACK
DUST COLLECTORS
FAN
CONVEYOR
CONVEYOR & ELEVATOR
FLUID BED DRYER
OIL
AIR
FAN
COMBUSTION CHAMBER
HOPPER
CONVEYOR-ELEVATOR
COKE STORAGE SILO
WEIGH FEEDER
MgSO3 STORAGE SILO
WEIGH FEEDER
CONVEYOR-ELEVATOR
BLOWER
PNEUMATIC CONVEYOR
MAKE-UP MgO STORAGE SILO
COVERED HOPPER CAR
WEIGH FEEDER
RECYCLE MgO STORAGE SILO
WEIGH FEEDER
ELEVATOR
AGITATOR
CONVEYOR-ELEVATOR
PUMP
SLURRYING TANK
STEAM TO STEAM PLANT
STEAM TO CONVERSION TANK
WASTE HEAT BOILER
DUST COLLECTOR
DUST COLLECTOR
BOILER FEED WATER
AIR
CONVEYOR ELEVATOR
OIL
AIR
FAN
FLUID BED CALCINER
CONVEYOR
MISCELLANEOUS HANDLING LOSSES
CONVEYOR
OIL
START-UP FURNACE
AIR
START-UP FAN
START-UP GAS PREHEATER
TO ATMOSPHERE
TO ATMOSPHERE
CATALYST
CONVERTER
FAN
AIR
CONVERTER HEAT EXCHANGER
PRIMARY HEAT EXCHANGERS
MAIN GAS BLOWER
STRIPPING TOWER
AIR
PUMP
PUMP
93% ACID DRYING TOWER
MAKE-UP WATER
PUMP TANK
98% ACID ABSORPTION TOWER
PUMP TANK
COOLING WATER
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PRODUCT ACID COOLERS
98% ACID COOLERS
93% ACID COOLERS
SEWER
PRODUCT STORAGE TANK
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RR TANK CAR
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NOTES:

○ ACTUAL LOCATIONS OF STREAM INLETS AND OUTLETS DEPEND UPON TYPE OF SCRUBBER AND/OR ABSORBER CHOSEN.

△ NEED FOR SURGE TANK AND AGITATOR DEPENDS UPON TYPE OF SCRUBBER AND/OR ABSORBER CHOSEN.

Figure B-1. Flow Diagram—Scheme A: Magnesia Slurry Scrubbing-Regeneration

STREAM NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
DESCRIPTION	COAL TO BOILER	COMBUSTION AIR TO AIR HEATER	COMBUSTION AIR TO BOILER	GAS TO COMBINER	GAS TO AIR HEATER	GAS TO PARTICULATE SCRUBBER	GAS TO SO_2 ABSORBER	GAS TO REHEATER	GAS TO FAN	GAS TO STACK	STEAM TO GAS REHEATER	MAKE-UP WATER TO PART. SCRUB.	RECYCLE SLURRY TO PART. SCRUB.	PART. SCRUB. SLURRY TO SURGE TANK	PARTICULATE SLURRY PRODUCT	RECYCLE POND WATER	MAKE-UP WATER TO SO_2 ABSORBER	RECYCLE SLURRY TO SO_2 ABSORBER	SO_2 ABSORBER SLURRY TO SURGE TANK	RECYCLE AND PRODUCT SLURRY
RATE, LBS./HR.	375M	4,518M	4,075M	4,404M	4,404M	1,218M	1,267M	1,289M	1,289M	1,289M	15.7M	55M	2,441M	2,563M	56M	47.6M	7,032	1,722M-2,444M	1,729M-2,409M	1,739M-2,453M
SCFM		986M	888M	943M	943M	260M	280M	286M	286M	286M										
GPM												110	4,700	4,603	103	95.1	14.1	3,160-6,813	3,163-6,820	3,102-6,391
PARTICULATES, LBS./HR.				32.7M	32.7M	8,635	42.9	56.8	56.8	56.8										
TEMPERATURE, °F		110	610	890	706	310	187	187	160	174	470			187					187	
SPECIFIC GRAVITY													1.03		1.09					1.09
VISCOSITY, CPS																				
UNDISSOLVED SOLIDS, %													.5		15					10
pH														3						8

STREAM NO.	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
DESCRIPTION	RECYCLE SLURRY	SLURRY TO PURGE TREATMENT	SLURRY TO SCREEN	UNDERFLOW TO LIQUOR TANK	OVERFLOW TO CONVERSION TANK	STEAM TO CONVERSION TANK	SLURRY TO CENTRIFUGE	TREATED LIQUOR TO LIQUOR TANK	LIQUOR TO LIQUOR TANK	LIQUOR TO RECYCLE	RECYCLE LIQUOR	LIQUOR TO SLURRYING TANK	FEED TO DRYER	OIL TO COMBUSTION CHAMBER	AIR TO COMBUSTION CHAMBER	DRYER GAS TO CYCLONE	DRYER GAS TO BAG COLLECTOR	RECYCLE GAS TO COMBUSTION CHAMBER	DRYER GAS TO STACK	COMBINED GASES TO ATMOSPHERE
RATE, LBS./HR.	[illegible]	DEPENDS UPON	272M	221M	51M	18.8M	102.1	SEE STREAM	68.6M	1,021M	228M	128M	66.4M	2,943	60.5M	136M	136M	45.0M	90.1M	5,246M
SCFM		MAGNESIA AND						22 NOTE							13.8M	35M	35M	11.0M	23.2M	1,167M
GPM	2,683-3,862	MAKE-UP	439	421	81.5		170		130	1,944	425	246								
PARTICULATES, LBS./HR.		WATER														5,960	894	1.4	2.8	230
TEMPERATURE, °F		IMPURITIES,				366	180									400				175
SPECIFIC GRAVITY		FLY ASH		1.05	1.25		1.20		1.06	1.05										
VISCOSITY, CPS		ENTRAINMENT,																		
UNDISSOLVED SOLIDS, %		ETC.		3.1	40		91		4.6	3.3										
pH																				

STREAM NO.	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60
DESCRIPTION	CYCLONE DUST TO CONVEYOR	BAG COLLECTOR DUST TO CONVEYOR	DRYER PRODUCT TO CONVEYOR	FEEDER DISCHARGE TO CONVEYOR	COKE TO CONVEYOR	FEED TO CALCINER	OIL TO CALCINER	AIR TO CALCINER	CALCINER GAS TO CYCLONE	CALCINER GAS TO WASTE HEAT BOILER	STEAM TO STEAM PLANT	CALCINER GAS TO QUENCH AIR	QUENCH AIR TO CALCINER GAS	COMBINED GASES TO BAG COLLECTOR	COMBINED GASES TO H_2SO_4 UNIT	CYCLONE DUST TO CALCINER	BAG COLLECTOR DUST TO CONVEYOR	CALCINER PRODUCT TO CONVEYOR	MISC. HANDLING LOSSES	RECYCLE MgO TO CONVEYOR
RATE, LBS./HR.	5,066	893	38.4M	38.6M	218	39.9M	3,220	46.3M	71.6M	71.6M	3,230	71.6M	62.6M	134M	134M	1,683	294	16.9M	240	16.6M
SCFM								10.1M	13.1M	13.1M		13.1M	12.8M	26.9M	26.9M					
GPM																				
PARTICULATES, LBS./HR.									1,900	297		297		297	3					
TEMPERATURE, °F			400						1,600		366	697		400				225		
SPECIFIC GRAVITY																				
VISCOSITY, CPS																				
UNDISSOLVED SOLIDS, %																				
pH																				

STREAM NO.	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80
DESCRIPTION	MAKE-UP MgO TO CONVEYOR	MgO SLURRY TO SO_2 ABSORBER	DRYING TOWER OUTLET GAS	CONVERTER OUTLET GAS	ABSORPTION TOWER OUTLET GAS	MAKE-UP WATER TO DRYING TOWER	RECYCLE ACID TO DRYING TOWER	RECYCLE ACID TO STRIPPING TOWER	RECYCLE ACID TO ABSORPTION TOWER	RECYCLE ACID TO COOLERS	RECYCLE ACID TO 93% ACID COOLERS	PRODUCT ACID TO STORAGE	COOLING WATER TO ACID COOLERS							
RATE, LBS./HR.	300	36.5M	129M	129M	109M	1,145	1,005M	129M	393M	155M	123M	32.2M	2,378M							
SCFM			35.1M	34.1M	22M															
GPM		65.7				2.29	4,110	146	4,110	179	157	35.4	4,756							
PARTICULATES, LBS./HR.												3								
TEMPERATURE, °F			100	840	167		100	168	160			100								
SPECIFIC GRAVITY		1.11					1.81	1.77	1.79			1.82								
VISCOSITY, CPS																				
UNDISSOLVED SOLIDS, %		15																		
pH																				

NOTES:

1. CALCULATIONS BASED ON:
   - a. 115% STOICHIOMETRIC MAGNESIA
   - b. 3.5% SULFUR IN COAL (DRY BASIS)
   - c. 12% ASH COAL (AS FIRED BASIS)
   - d. 92% OF SULFUR IN COAL EVOLVES AS SO_2
   - e. 75% OF ASH IN COAL EVOLVES AS FLY ASH
   - f. 99.5% REMOVAL OF PARTICULATES TO SCRUBBER
   - g. 90% SO_2 REMOVAL
2. PARTICULATES SHOULD BE ADDED TO GAS TO GET TOTAL STREAM RATE
3. STREAM NUMBERS 6-20, 23-25, 31 & 32 ARE ONE OF FOUR SIMILAR STREAMS
4. STREAM NUMBERS 27 & 29 ARE ONE OF TWO SIMILAR STREAMS
5. RATES FOR STREAM NUMBERS 18-21 DEPEND UPON TYPE OF SO_2 ABSORBER CHOSEN

SYMBOL IN TABLE
M.... THOUSAND

Figure B-2. Material Balance–Scheme A: Magnesia Slurry Scrubbing-Regeneration

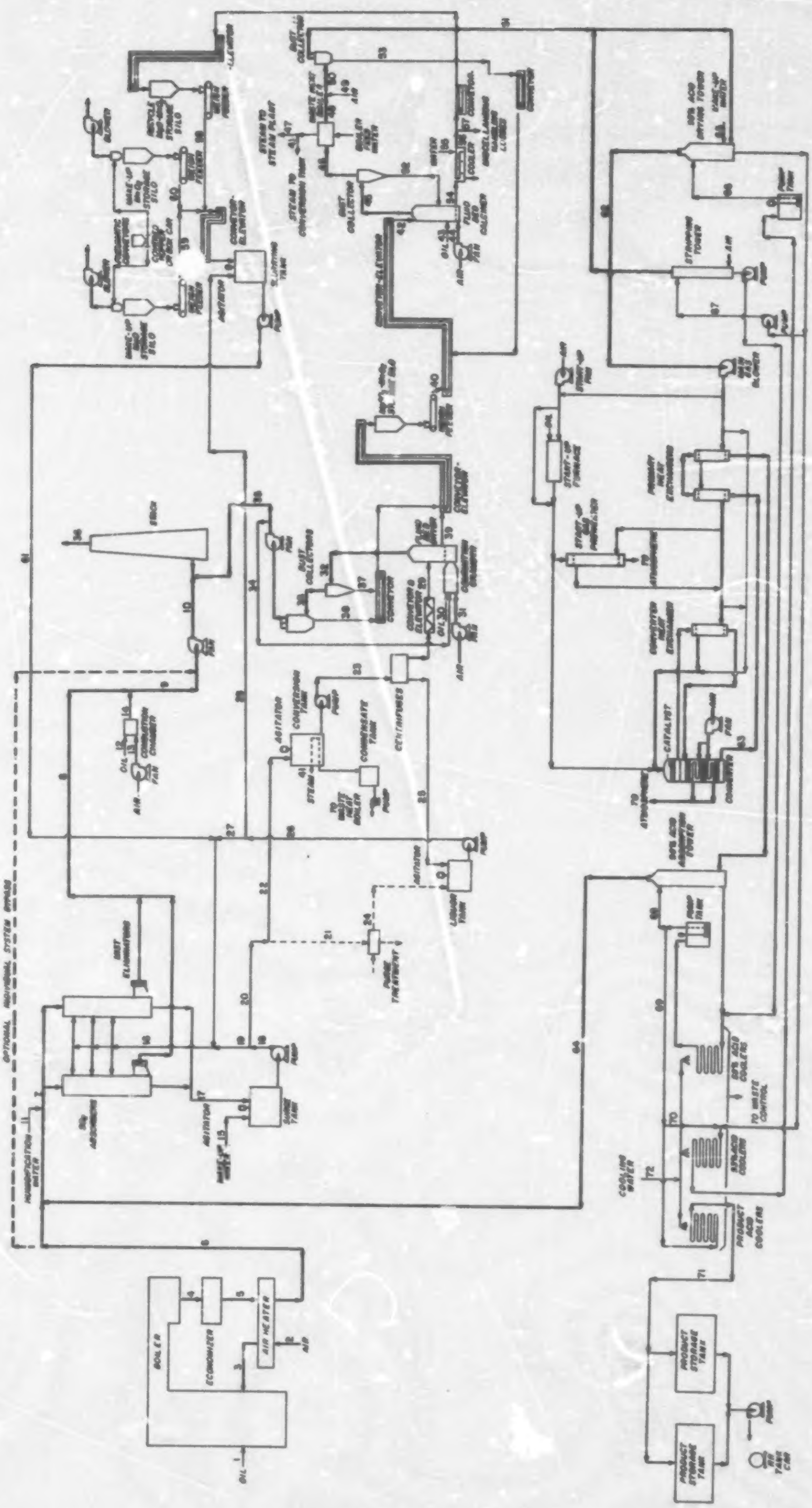

BOILER
ECONOMIZER
AIR HEATER
AIR
OIL
STACK
CATALYST
CONVERTER
START-UP FURNACE
PRIMARY HEAT EXCHANGER
STRIPPING TOWER
COOLING WATER
PRODUCT ACID COOLERS
PRODUCT STORAGE TANK

Figure B-3. Flow Diagram–Scheme B: MgO-MnO$_2$ Slurry Scrubbing-Regeneration

STREAM NO	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
DESCRIPTION	OIL TO BOILER	COMBUSTION AIR TO AIR HEATER	COMBUSTION AIR TO BOILER	GAS TO ECONOMIZER	GAS TO AIR HEATER	GAS TO HUMIDIFICATION	GAS TO SO_2 ABSORBERS	GAS TO REHEATING	GAS TO FAN	GAS TO STACK	HUMIDIFICATION WATER TO DUCT	OIL TO COMBUSTION CHAMBER	AIR TO COMBUSTION CHAMBER	REHEAT GAS TO DUCT	MAKE-UP WATER TO SO_2 ABSORBERS	RECYCLE SLURRY TO SO_2 ABSORBERS	SO_2 ABSORBERS SLURRY TO SURGE TANK	RECYCLE AND PRODUCT SLURRY	RECYCLE SLURRY	PRODUCT SLURRY
RATE, LBS./HR	243 M	3,798 M	3,420 M	3,655 M	3,655 M	1,006 M	1,043 M	1,063 M	1,077 M	1,077 M	23.6 M	390	134 M	138 M	21.0 M	1,274 M	1,260 M	1,281 M	1,263 M	17.7 M
SCFM		834 M	753 M	796 M	796 M	213 M	230 M	230 M	241 M	241 M			5,910	2,016						
GPM	503										47.5				48.1	1,644	1,625	1,668	1,630	22.8
PARTICULATES, LBS./HR				243	243	60.8	60.8	60.8	61.2	61.2				0.4						
TEMPERATURE, °F		110	610	890	705	310	210	139	180	174										
SPECIFIC GRAVITY																		1.55		
VISCOSITY, CPS																				
UNDISSOLVED SOLIDS, %																		68		
pH																		8		

STREAM NO	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
DESCRIPTION	SLURRY TO PURGE TREATMENT	SLURRY TO CONVERSION TANK	SLURRY TO CENTRIFUGE	TREATED LIQUOR TO LIQUOR TANK	LIQUOR TO LIQUOR TANK	LIQUOR TO RECYCLE	RECYCLE LIQUOR	LIQUOR TO SLURRYING TANK	FEED TO DRYER	OIL TO COMBUSTION CHAMBER	AIR TO COMBUSTION CHAMBER	DRYER GAS TO CYCLONE	DRYER GAS TO BAG COLLECTOR	RECYCLE GAS TO COMBUSTION CHAMBER	DRYER GAS TO STACK	COMBINED GASES TO ATMOSPHERE	CYCLONE DUST TO CONVEYOR	BAG COLLECTOR DUST TO CONVEYOR	DRYER PRODUCT TO CONVEYOR	FEEDER DISCHARGE TO CONVEYOR
RATE, LBS./HR	DEPENDS	17.7 M	35.4 M	SEE STREAM	14.8 M	30.4 M	4,935	8,701	42.4 M	1,581	32.2 M	73.7 M	73.7 M	24.4 M	49.3 M	4,357 M	2,749	484	23.7 M	27.0 M
SCFM	UPON			21 NOTE							7,075	13.0 M	13.0 M	6,285	12.7 M	977 M				
GPM	MAGNESIUM,	22.8	50.6		23.7	47.4	8.22	14.5												
PARTICULATES, LBS./HR	MANGANESE											3,234	485	0.7	1.5	246				
TEMPERATURE, °F	CHLORIDE AND		180									400				175			400	
SPECIFIC GRAVITY	MAKE-UP		1.4		1.2															
VISCOSITY, CPS	WATER																			
UNDISSOLVED SOLIDS, %	IMPURITIES,		54		13															
pH	ETC.																			

STREAM NO	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60
DESCRIPTION	STEAM TO CONVERSION TANK	FEED TO CALCINER	OIL TO CALCINER	AIR TO CALCINER	CALCINER GAS TO CYCLONE	CALCINER GAS TO WASTE HEAT BOILER	STEAM TO STEAM PLANT	CALCINER GAS TO QUENCH AIR	QUENCH AIR TO CALCINER GAS	COMBINED GASES TO BAG COLLECTOR	COMBINED GASES TO H_2SO_4 UNIT	CYCLONE DUST TO CALCINER	BAG COLLECTOR DUST TO CONVEYOR	CALCINER PRODUCT TO COOLER	WATER TO COOLER	CALCINER PRODUCT TO CONVEYOR	MISC. HANDLING LOSSES	RECYCLE MgO TO CONVEYOR	MAKE-UP MgO TO CONVEYOR	MAKE-UP MnO_2 TO CONVEYOR
RATE, LBS./HR	3,964	27.2 M	1,977	28.8 M	41.9 M	41.9 M	8,813	41.9 M	33.4 M	75.3 M	75.3 M	1,269	222	14.9 M	19.7 M	14.9 M	262	14.7 M	160	106
SCFM				6,195	7,810	7,810		7,810	7,335	15.1 M	15.1 M									
GPM															39.4					
PARTICULATES, LBS./HR					1,493	224		224		224	2.2									
TEMPERATURE, °F	366				1,800		366	671		400				345		225				
SPECIFIC GRAVITY																				
VISCOSITY, CPS																				
UNDISSOLVED SOLIDS, %																				
pH																				

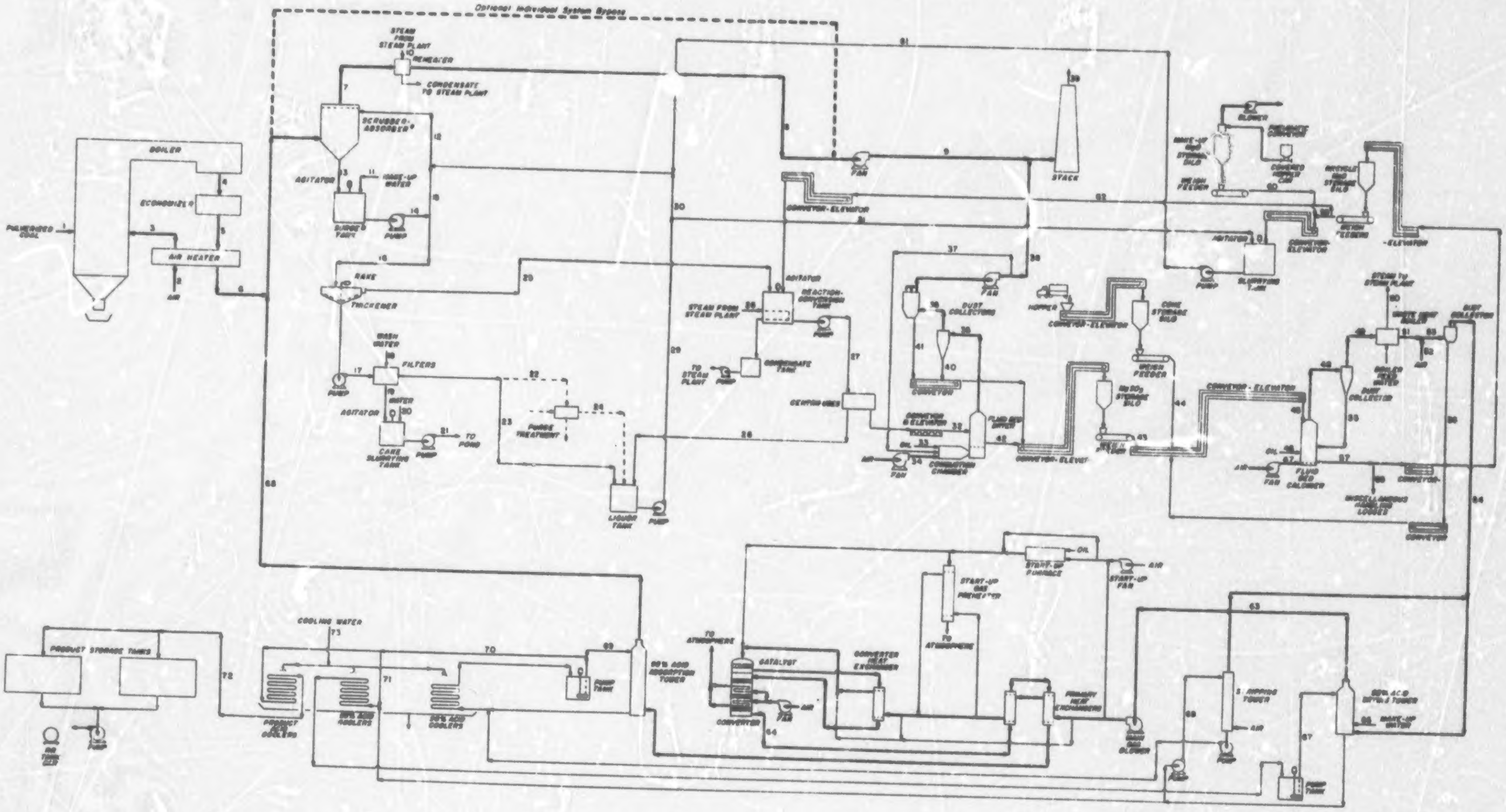
STREAM NO	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80
DESCRIPTION	SLURRY TO SO_2 ABSORBERS	DRYING TOWER OUTLET GAS	CONVERTER OUTLET GAS	ABSORPTION TOWER OUTLET GAS	MAKE-UP WATER TO DRYING TOWER	RECYCLE ACID TO DRYING TOWER	RECYCLE ACID TO STRIPPING TOWER	RECYCLE ACID TO ABSORPTION TOWER	RECYCLE ACID TO COOLERS	RECYCLE ACID TO 98% ACID COOLERS	PRODUCT ACID TO STORAGE	COOLING WATER TO ACID COOLERS								
RATE, LBS./HR	5,909	72.8 M	72.2 M	58.4 M	297	535 M	68.9 M	530 M	68.7 M	68.5 M	13.8 M	1,264 M								
SCFM		14.0 M	13.5 M	12.4 M																
GPM	7.42				0.59	592	77.3	592	30.4	70.8	10.9	2,528								
PARTICULATES, LBS./HR											2.2									
TEMPERATURE, °F		100	840	160		100	163	160			100									
SPECIFIC GRAVITY	1.55					1.81	1.77	1.79			1.82									
VISCOSITY, CPS																				
UNDISSOLVED SOLIDS, %	60																			
pH																				

NOTES:

1. CALCULATIONS BASED ON:
   - a. 118% STOICHIOMETRIC MAGNESIA
   - b. 2.5% SULFUR IN OIL
   - c. 90% SO_2 REMOVAL
2. PARTICULATES SHOULD BE ADDED TO GAS TO GET TOTAL STREAM RATE
3. STREAM NUMBERS 16-20, 22, 27 & 61 ARE ONE OF FOUR SIMILAR STREAMS
4. STREAM NUMBERS 33 & 35 ARE ONE OF TWO SIMILAR STREAMS
5. RATES FOR STREAM NUMBERS 16-19 ARE BASED ON TEST DATA FOR A COCURRENT SPRAY ABSORBER

SYMBOL IN TABLE
M.....THOUSAND

Figure B-4. Material Balance–Scheme B: MgO-MnO_2 Slurry Scrubbing-Regeneration


Optional Individual System Bypass
PULVERIZED COAL
BOILER
ECONOMIZER
AIR HEATER
AIR
STEAM FROM STEAM PLANT
REHEATER
CONDENSATE TO STEAM PLANT
SCRUBBER-ABSORBER a
AGITATOR
MAKE-UP WATER
SURGE TANK b
PUMP
RAKE
THICKENER
WASH WATER
FILTERS
WATER
AGITATOR
CAKE SLURRYING TANK
TO POND
PURGE TREATMENT
LIQUOR TANK
FAN
STACK
CONVEYOR-ELEVATOR
AGITATOR
REACTION-CONVERSION TANK
STEAM FROM STEAM PLANT
CONDENSATE TANK
TO STEAM PLANT
CENTRIFUGES
DUST COLLECTORS
CONVEYOR
CONVEYOR & ELEVATOR
FLUID BED DRYER
OIL
AIR
COMBUSTION CHAMBER
CONVEYOR-ELEVATOR
HOPPER
COKE STORAGE SILO
WEIGH FEEDER
$MgSO_3$ STORAGE SILO
BLOWER
PNEUMATIC CONVEYOR
MAKE-UP MgO STORAGE SILO
COVERED HOPPER CAR
RECYCLE MgO STORAGE SILO
-ELEVATOR
SLURRYING TANK
STEAM TO STEAM PLANT
WASTE HEAT BOILER
BOILER FEED WATER
DUST COLLECTOR
FLUID BED CALCINER
MISCELLANEOUS HANDLING LOSSES
START-UP FURNACE
START-UP FAN
START-UP GAS PREHEATER
TO ATMOSPHERE
CATALYST
CONVERTER
CONVERTER HEAT EXCHANGER
PRIMARY HEAT EXCHANGERS
MAIN GAS BLOWER
STRIPPING TOWER
98% ACID DRYING TOWER
MAKE-UP WATER
PUMP TANK
98% ACID ABSORPTION TOWER
COOLING WATER
98% ACID COOLERS
PRODUCT ACID COOLERS
PRODUCT STORAGE TANKS
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2
3
4
5
6
7
8
9
10
11
12
13
14
15
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73

NOTE:

a. ACTUAL LOCATIONS OF STREAM INLET AND OUTLET DEPEND UPON TYPE OF SCRUBBER-ABSORBER CHOSEN.

b. NEED FOR SURGE TANK AND AGITATOR DEPENDS UPON TYPE OF SCRUBBER-ABSORBER CHOSEN.

Figure B-5. Flow Diagram—Scheme C: Magnesia Clear Liquor Scrubbing-Regeneration

STREAM NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
DESCRIPTION	COAL TO BOILER	COMBUSTION AIR TO AIR HEATER	COMBUSTION AIR TO BOILER	GAS TO ECONOMIZER	GAS TO AIR HEATER	GAS TO SCRUBBER-ABSORBER	GAS TO REHEATER	GAS TO FAN	GAS TO STACK	STEAM TO GAS REHEATER	MAKE-UP WATER TO SURGE TANK	RECYCLE LIQUOR TO SCRUBBER-ABSORBER	SCRUBBER-ABSORBER LIQUOR TO SURGE TANK	RECYCLE AND PRODUCT LIQUOR	RECYCLE LIQUOR	FEED TO THICKENER	UNDERFLOW TO FILTER	WASH WATER TO FILTER	CAKE TO SLURRYING TANK	WATER TO SLURRYING TANK
RATE, LBS./HR	375M	4,518M	4,075M	4,404M	4,404M	1,212M	1,283M	1,283M	1,283M	16.5M	55.3M	4,200M	4,151M	4,806M	4,031M	178M	55.9M	16.8M	24M	176M
SCFM		984M	808M	943M	943M	260M	282M	282M	282M											
GPM											111	7,985	7,832	7,936	7,606	331	94	33.6		358
PARTICULATES, LBS./HR.				33.7M	33.7M	8,435	54.2	54.2	54.2											
TEMPERATURE, °F		110	610	890	705	310	125	160	174	470			125							
SPECIFIC GRAVITY														1.06			1.19			
VISCOSITY, CPS																				
UNDISSOLVED SOLIDS, %														4.8			30			
pH														5						

STREAM NO.	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
DESCRIPTION	CAKE SLURRY TO POND	LIQUOR TO PURGE TREATMENT	FILTRATE TO LIQUOR TANK	TREATED LIQUOR TO LIQUOR TANK	OVERFLOW TO REACTION-CONVERSION TANK	STEAM TO REACTION-CONVERSION TANK	SLURRY TO CENTRIFUGE	LIQUOR TO LIQUOR TANK	LIQUOR TO RECYCLE	RECYCLE LIQUOR	LIQUOR TO SLURRYING TANK	FEED TO DRYER	OIL TO COMBUSTION CHAMBER	AIR TO COMBUSTION CHAMBER	DRYER GAS TO CYCLONE	DRYER GAS TO BAG COLLECTOR	RECYCLE GAS TO COMBUSTION CHAMBER	DRYER GAS TO STACK	COMBINED GASES TO ATMOSPHERE	CYCLONE DUST TO CONVEYOR
RATE, LBS./HR.	224M	DEPENDS	48.7M	SEE STREAM	590M	20.7M	899M	871M	639M	140M	79.9M	56.8M	2474	50.9M	116M	116M	38.5M	77.3M	5,200M	4,982
SCFM		UPON		22 NOTE										11.1M	30.1M	30.1M	10M	20.1M	1,140M	
GPM	411	MAGNESIA,	956		1,145		570	896	1,266	277	158									
PARTICULATES, LBS./HR.		FLY ASH &													5,180	768	1.2	2.3	819	
TEMPERATURE, °F		MAKE-UP				366	100								400				175	
SPECIFIC GRAVITY	1.03	WATER	1.02		1.03		1.05	1.01												
VISCOSITY, CPS		IMPURITIES,																		
UNDISSOLVED SOLIDS, %	15	ETC.					20	1												
pH							9													

STREAM NO.	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60
DESCRIPTION	BAG COLLECTOR DUST TO CONVEYOR	DRYER PRODUCT TO CONVEYOR	FEEDER DISCHARGE TO CONVEYOR	COKE TO CONVEYOR	FEED TO CALCINER	OIL TO CALCINER	AIR TO CALCINER	CALCINER GAS TO CYCLONE	CALCINER GAS TO WASTE HEAT BOILER	STEAM TO STEAM PLANT	CALCINER GAS TO QUENCH AIR	QUENCH AIR TO CALCINER GAS	COMBINED GASES TO BAG COLLECTOR	COMBINED GASES TO H_2SO_4 UNIT	CYCLONE DUST TO CALCINER	BAG COLLECTOR DUST TO CONVEYOR	CALCINER PRODUCT TO CONVEYOR	MISC HANDLING LOSSES	RECYCLE MgO TO CONVEYOR	MAKE-UP MgO TO CONVEYOR
RATE, LBS./HR	766	27.7M	32.9M	33	33.2M	2,772	39.9M	61.3M	61.3M	16M	61.3M	33.6M	115M	113M	1,170	204	13.8M	205	4086	246
SCFM							8,685	11.8M	11.8M		11.8M	11.8M	23.1M	23.1M						
GPM																				
PARTICULATES, LBS./HR								1,376	206		206		206	2.1						
TEMPERATURE, °F		400						1,600		366	638		400				810			
SPECIFIC GRAVITY																				
VISCOSITY, CPS																				
UNDISSOLVED SOLIDS, %																				
pH																				

STREAM NO	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80
DESCRIPTION	MgO SLURRY TO SCRUBBER-ABSORBER	MgO TO REACTION-CONVERSION TANK	DRYING TOWER OUTLET GAS	CONVERTER OUTLET GAS	ABSORPTION TOWER OUTLET GAS	MAKE-UP WATER TO DRYING TOWER	RECYCLE ACID TO DRYING TOWER	RECYCLE ACID TO STRIPPING TO[illegible]	RECYCLE ACID TO ABSORPTION TOWER	RECYCLE ACID TO COOLERS	RECYCLE ACID TO 93% ACID COOLERS	PRODUCT ACID TO STORAGE	COOLING WATER TO ACID COOLERS							
RATE, LBS./HR	81.4M	8,674	110M	110M	88.2M	947	868M	111M	853M	138M	105M	27.0M	2,042M							
SCFM			21.5M	20.6M	18.9M															
GPM	40.8					1.89	953	126	953	149	117	30.4	4,083							
PARTICULATES, LBS./HR.												2.1								
TEMPERATURE, °F			100	840	160		100	163	160			100								
SPECIFIC GRAVITY	1.05						1.81	1.77	1.79			1.82								
VISCOSITY, CPS																				
UNDISSOLVED SOLIDS, %	8.2																			
pH																				

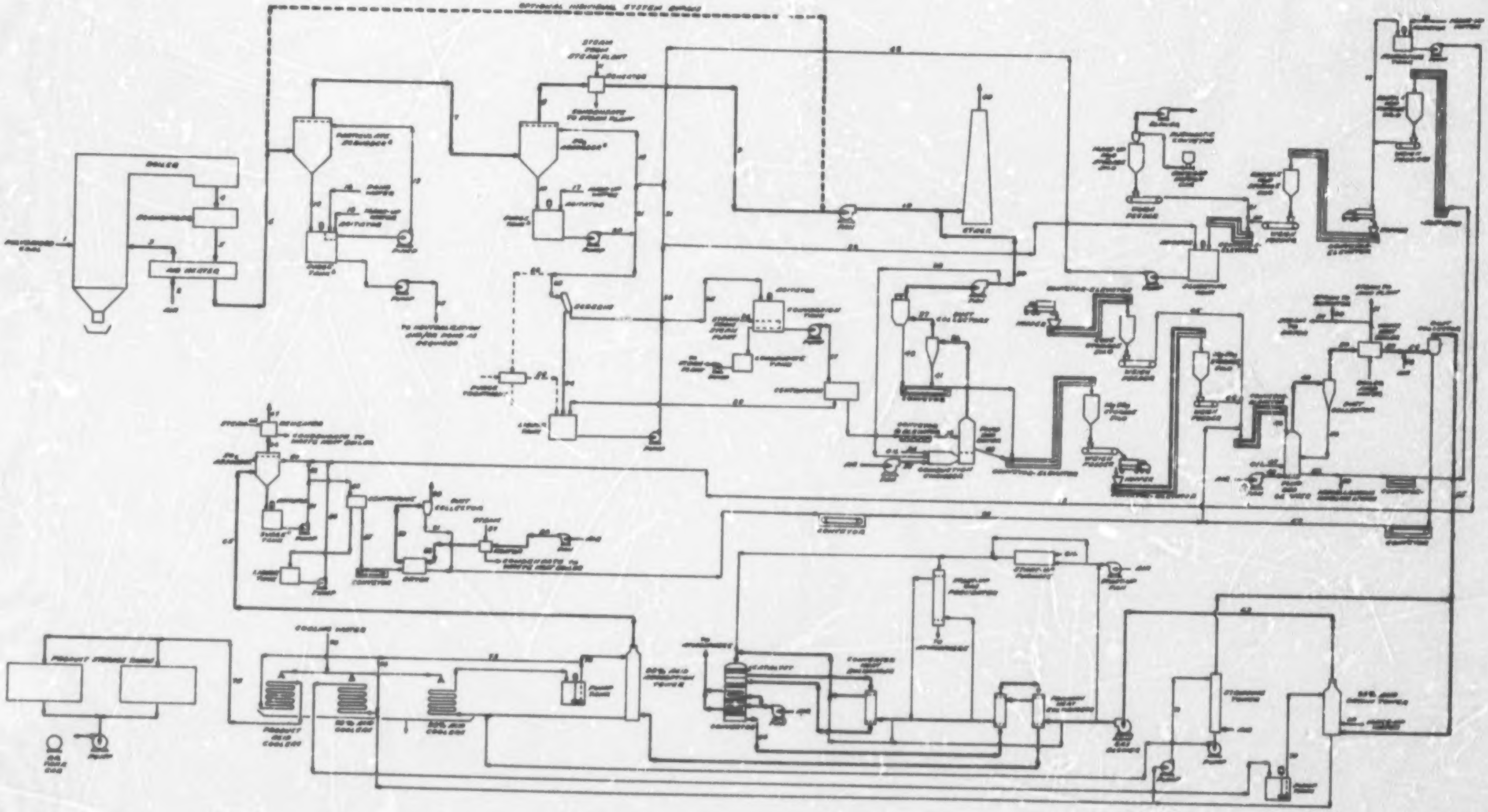
NOTES:

1. CALCULATIONS BASED ON:
   - a. 100% STOICHIOMETRIC MAGNESIA
   - b. 3.5% SULFUR IN COAL (DRY BASIS)
   - c. 12% ASH COAL (AS FIRED BASIS)
   - d. 92% OF SULFUR IN COAL EVOLVES AS SO_2
   - e. 75% OF ASH IN COAL EVOLVES AS FLY ASH
   - f. 99.5% REMOVAL OF PARTICULATES TO SCRUBBER
   - g. 77% SO_2 REMOVAL
2. PARTICULATES SHOULD BE ADDED TO GAS TO GET TOTAL STREAM RATE
3. STREAM NUMBERS 6-10, 30 & 61 ARE ONE OF FOUR SIMILAR STREAMS
4. STREAM NUMBERS 17-19, 23, 27 & 28 ARE ONE OF TWO SIMILAR STREAMS
5. RATES FOR STREAM NUMBERS 12-15 ARE BASED ON TEST DATA FOR A VENTURI SCRUBBER-ABSORBER

SYMBOL IN TABLE

M.... THOUSAND

Figure B-6. Material Balance–Scheme C: Magnesia Clear Liquor Scrubbing-Regeneration



OPTIONAL INDIVIDUAL SYSTEM BYPASS
PULVERIZED COAL
BOILER
AIR HEATER
AIR
STEAM FROM STEAM PLANT
PUMP
STACK
COOLING WATER
PRODUCT STORAGE TANKS

NOTES:

a. ACTUAL LOCATIONS OF STREAM INLETS AND OUTLETS DEPEND UPON TYPE OF SCRUBBER AND/OR ABSORBER CHOSEN

b. NEED FOR SURGE TANK AND AGITATOR DEPENDS UPON TYPE OF SCRUBBER AND/OR ABSORBER CHOSEN

Figure B-7. Flow Diagram—Scheme D: Magnesia Slurry Scrubbing-Regeneration Central Process Concept

STREAM NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
DESCRIPTION	COAL TO BOILER	COMBUSTION AIR TO AIR HEATER	COMBUSTION AIR TO BOILER	GAS TO ECONOMIZER	GAS TO AIR HEATER	GAS TO PARTICULATE SCRUBBER	GAS TO SO_2 ABSORBER	GAS TO REHEATER	GAS TO FAN	GAS TO STACK	STEAM TO GAS REHEATER	MAKE-UP WATER TO PART. SCRUB.	RECYCLE SLURRY TO PART. SCRUB.	PART. SCRUB. SLURRY TO SURGE TANK	PARTICULATE SLURRY PRODUCT	RECYCLE POND WATER	MAKE-UP WATER TO SO_2 ABSORBER	RECYCLE SLURRY TO SO_2 ABSORBER	SO_2 ABSORBER SLURRY TO SURGE TANK	RECYCLE AND PRODUCT SLURRY	RECYCLE SLURRY	SLURRY TO PURGE TREATMENT	SLURRY TO THICKENER	UNDERFLOW TO LIQUOR TANK	OVERFLOW TO CONVERSION TANK
RATE, LBS./HR	375 M	4,510 M	4,075 M	4,400 M	4,400 M	1,112 M	1,367 M	1,368 M	1,368 M	1,368 M	18.4 M	55 M	2,001 M	2,056 M	50 M	476 M	6,010	[illegible]	[illegible]	[illegible]	[illegible]	BYPASS UPON	262 M	200 M	40.0 M
SCFM		964 M	868 M	943 M	943 M	260 M	280 M	280 M	280 M	280 M												ANALYSIS OF			
GPM												110	4,760	4,003	102	251	12.0	2,110-4,080	2,160-6,100	2,107-6,301	2,007-4,057	MAKE-UP	524	400	79.1
PARTICULATES, LBS./HR				23.7 M	23.7 M	6,035	62.9	55.6	55.6	55.6												WATER			
TEMPERATURE, °F		110	610	850	705	310	127	127	160	170	470			127					127			IMPURITIES &			
SPECIFIC GRAVITY													1.08		1.08					1.09		FLY ASH		1.05	1.05
VISCOSITY, CPS																						SUSPENDED			
UNDISSOLVED SOLIDS, %													5		15					10		575		31	40
pH														3						8					

STREAM NO.	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50
DESCRIPTION	STEAM TO CONVERSION TANK	SLURRY TO CENTRIFUGE	TREATED LIQUOR TO [illegible]	LIQUOR TO LIQUOR TANK	LIQUOR TO RECYCLE	RECYCLE LIQUOR	LIQUOR TO SLURRYING TANK	FEED TO DRYER	OIL TO COMBUSTION CHAMBER	AIR TO COMBUSTION CHAMBER	DRYER GAS TO CYCLONE	DRYER GAS TO GAS COLLECTOR	RECYCLE GAS TO COMBUSTION CHAMBER	DRYER GAS TO STACK	COMBINED GASES TO ATMOSPHERE	CYCLONE DUST TO CONVEYOR	BAG COLLECTOR DUST TO CONVEYOR	DRYER PRODUCT TO CONVEYOR	[illegible] TO CONVEYOR	COKE TO CONVEYOR	FEED TO CALCINER	OIL TO CALCINER	AIR TO CALCINER	CALCINER GAS TO CYCLONE	CALCINER GAS TO WASTE HEAT BOILER
RATE, LBS./HR	12.4 M	96.8 M	SEE STREAM	66.6 M	300 M	817 M	184 M	64.4 M	2,674	58.7 M	192 M	192 M	46.6 M	60 M	5,126 M	4,956	871	32.8 M	32.6 M	185	34.7 M	2,810	40.4 M	46.5 M	62.5 M
SCFM			22, NOTE							12.8 M	96.3 M	34.9 M	11.8 M	20.0 M	1,162 M								8,804	11.5 M	11.5 M
GPM		165		126	1,005	412	236																		
PARTICULATES, LBS./HR											5,830	874	1.6	2.7	885									1,671	881
TEMPERATURE, °F	366	190									400				175									1,034	
SPECIFIC GRAVITY		1.20		1.06	1.05																				
VISCOSITY, CPS																									
UNDISSOLVED SOLIDS, %		31		6.7	8.8																				
pH																									

STREAM NO.	51	52	53	54	55	56	57	58	59	60	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75
DESCRIPTION	STEAM TO ACID PLANT	CALCINER GAS TO QUENCH AIR	QUENCH AIR TO CALCINER GAS	COMBINED GASES TO BAG COLLECTOR	COMBINED GASES TO H_2SO_4 UNIT	CYCLONE DUST TO CALCINER	BAG COLLECTOR DUST TO CONVEYOR	CALCINED PRODUCT TO CONVEYOR	MISC. HANDLING LOSSES	RECYCLE MgO TO CONVEYOR	MAKE-UP MgO TO CONVEYOR	MgO SLURRY TO SO_2 ABSORBER	DRYING TOWER OUTLET GAS	CONVERTER OUTLET GAS	GAS TO SO_3 ABSORBER	GAS TO REHEATER	GAS TO ATMOSPHERE	STEAM TO GAS REHEATER	MAKE-UP WATER TO DRYING TOWER	RECYCLE ACID TO DRYING TOWER	RECYCLE ACID TO STRIPPING TOWER	RECYCLE ACID TO ABSORPTION TOWER	RECYCLE ACID TO COOLERS	RECYCLE ACID TO 98% ACID COOLERS	PRODUCT ACID TO STORAGE
RATE, LBS./HR	4,818	62.5 M	20.7 M	117 M	117 M	1,850	810	16.7 M	310	16 M	416	36.1 M	113 M	118 M	90 M	91.2 M	91.2 M	5,600	390	679 M	118 M	969 M	132 M	10 M	20.2 M
SCFM		11.5 M	19.1 M	22.5 M	23.5 M								81.0 M	81 M	18.8 M	18.8 M	18.8 M								
GPM												65.2							1.56	271	158	271	151	180	81
PARTICULATES, LBS./HR		281		281	8.2																				8.5
TEMPERATURE, °F	366	697		400				282					100	800	160	75	175	366		100	163	160			100
SPECIFIC GRAVITY												1.11								1.81	1.77	1.79			1.83
VISCOSITY, CPS																									
UNDISSOLVED SOLIDS, %												15													
pH																									

STREAM NO.	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	100
DESCRIPTION	COOLING WATER TO ACID COOLERS	RECYCLE MgO TO SLURRYING TANK	MAKE-UP WATER TO SLURRYING TANK	MgO SLURRY TO SO_2 ABSORBER	RECYCLE SLURRY TO SO_2 ABSORBER	RECYCLE AND PRODUCT SLURRY	RECYCLE SLURRY	SLURRY TO CENTRIFUGE	LIQUOR TO RECYCLE	DRYER FEED TO CONVEYOR	AIR TO AIR HEATER	STEAM TO AIR HEATER	HEATED AIR TO DRYER	DRYER GAS TO BAG COLLECTOR	GAS TO ATMOSPHERE	BAG COLLECTOR DUST TO CONVEYOR	COMBINED MATERIAL TO CONVEYING								
RATE, LBS./HR	2,050 M	400	2,020	3,720	1,100-2,020 M	1,100-2,210 M	910-2,020 M	19.4 M	17.6 M	2,055	23.7 M	1,764	38.7 M	25.8 M	25.8 M	396	826								
SCFM											5,050		5,050	5,050	5,050										
GPM	4,100		4.04	6	200-407	202-406	167-371	35.6	36.6																
PARTICULATES, LBS./HR														397	1.1										
TEMPERATURE, °F											80	366	350	180											
SPECIFIC GRAVITY				1.07		1.09																			
VISCOSITY, CPS																									
UNDISSOLVED SOLIDS, %				18		10			1																
pH						8																			

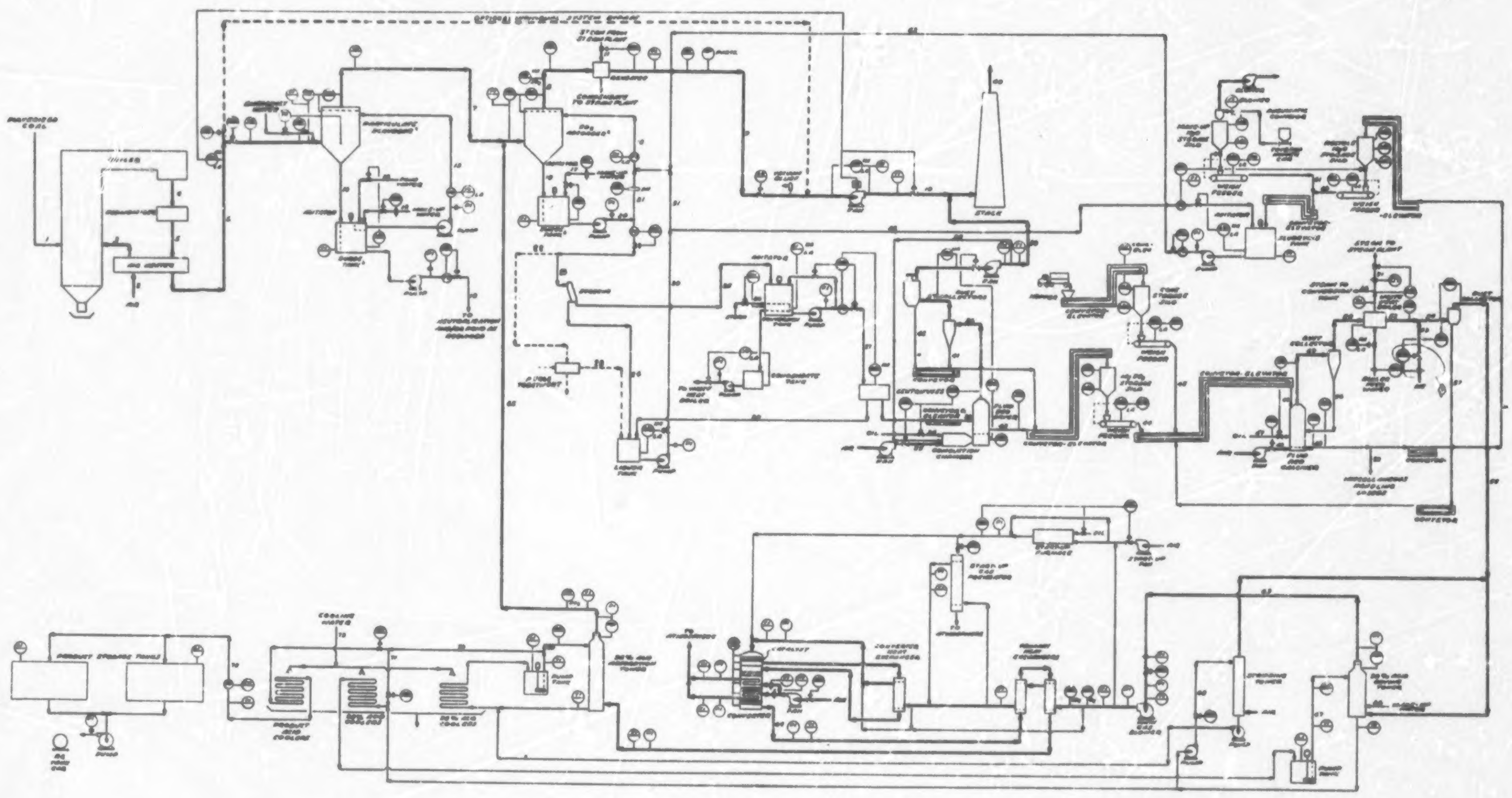
STREAM NO.	101	102	103	104	105	106	107	108	109	110	111	112	113	114	115	116	117	118	119	120	121	122	123	124	125
DESCRIPTION																									
RATE, LBS./HR																									
SCFM																									
GPM																									
PARTICULATES, LBS./HR																									
TEMPERATURE, °F																									
SPECIFIC GRAVITY																									
VISCOSITY, CPS																									
UNDISSOLVED SOLIDS, %																									
pH																									

NOTES:

1. CALCULATIONS BASED ON:
   - a. 110% STOICHIOMETRIC MAGNESIA
   - b. 3.5% SULFUR IN COAL (DRY BASIS)
   - c. 12% ASH COAL (AS FIRED BASIS)
   - d. 95% OF SULFUR IN COAL EVOLVES AS SO_2
   - e. 75% OF ASH IN COAL EVOLVES AS FLY ASH
   - f. 99.5% REMOVAL OF PARTICULATES TO SCRUBBER
   - g. 90% SO_2 REMOVAL AT STEAM PLANT & 99.7% RECOVERY AT SULFURIC ACID PLANT
   - h. 7 M HOURS/OPERATING YEAR AT STEAM PLANT (STREAM NUMBERS 1-42 & 60-62) & 8 M HOURS AT SULFURIC ACID PLANT (STREAM NUMBERS 43-59 & 63-75)
2. PARTICULATES SHOULD BE ADDED TO GAS TO GET TOTAL STREAM RATE
3. STREAM NUMBERS 6-21, 85-86, 91 & 92 ARE ONE OF FOUR SIMILAR STREAMS
4. STREAM NUMBERS 87 & 88 ARE ONE OF TWO SIMILAR STREAMS
5. RATES FOR STREAM NUMBERS 18-21 & 80-82 DEPEND UPON TYPE OF SO_2 ABSORBER CHOSEN

SYMBOL IN TABLE
M.... THOUSAND

Figure B-8. Material Balance–Scheme D: Magnesia Slurry Scrubbing-Regeneration Central Process Concept



PULVERIZED COAL
BOILER
AIR HEATER
PARTICULATE SCRUBBER
SO2 ABSORBER
PUMP
STACK
FAN
CENTRIFUGES
CONVEYOR
COMBUSTION CHAMBER
CONVEYOR-ELEVATOR
WEIGH FEEDER
STEAM TO STEAM PLANT
CONVEYOR
CATALYST
CONVERTER
PRODUCT STORAGE TANKS
STRIPPING TOWER

NOTES:

a. ACTUAL LOCATIONS OF STREAM INLETS AND OUTLETS DEPEND UPON TYPE OF SCRUBBER AND/OR ABSORBER CHOSEN.

b. NEED FOR SURGE TANK AND AGITATOR DEPENDS UPON TYPE OF SCRUBBER AND/OR ABSORBER CHOSEN

c. STANDARD I.S.A. IDENTIFICATION LETTERS USED ON INSTRUMENTATION.

Figure B-9. Control Diagram—Scheme A: Magnesia Slurry Scrubbing-Regeneration

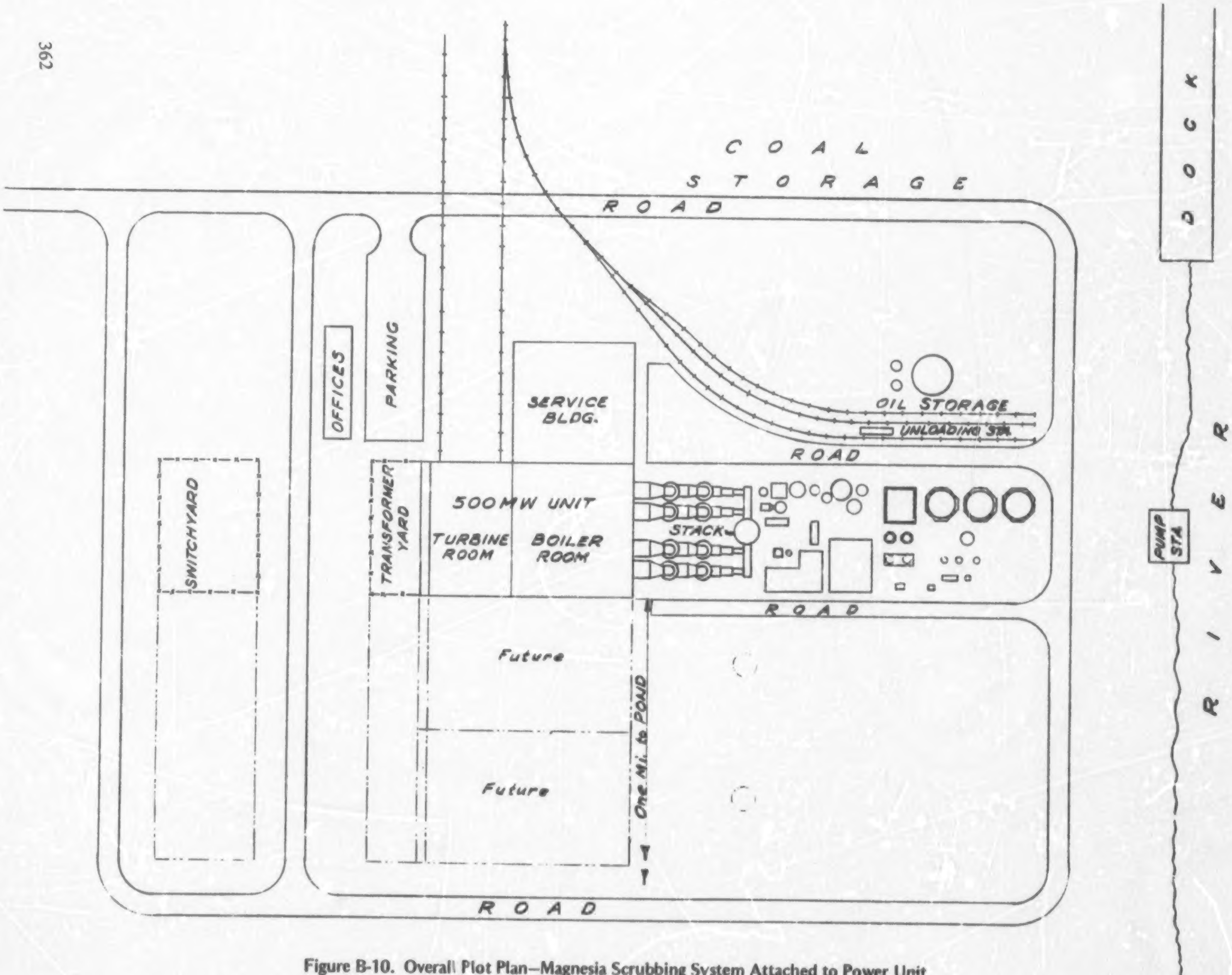

COAL STORAGE
ROAD
DOCK
RIVER
PUMP STA
OIL STORAGE
UNLOADING STA.
ROAD
SERVICE BLDG.
500 MW UNIT
TURBINE ROOM
BOILER ROOM
STACK
ROAD
TRANSFORMER YARD
OFFICES
PARKING
SWITCHYARD
Future
Future
One Mi. to POND
ROAD

Figure B-10. Overall Plot Plan—Magnesia Scrubbing System Attached to Power Unit

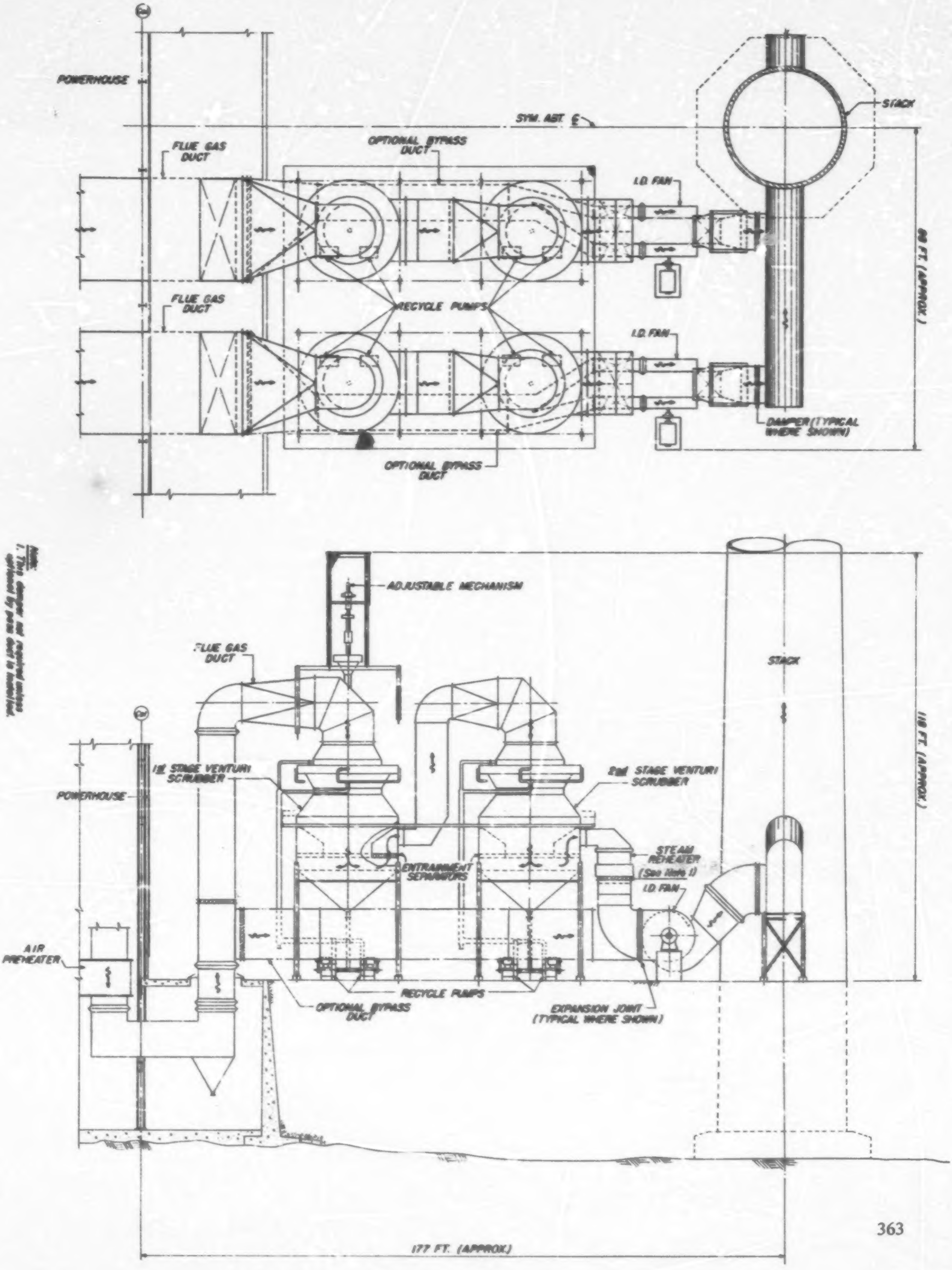

POWERHOUSE
SYM. ABT. ℄
STACK
FLUE GAS DUCT
OPTIONAL BYPASS DUCT
I.D. FAN
88 FT. (APPROX.)
RECYCLE PUMPS
FLUE GAS DUCT
I.D. FAN
DAMPER (TYPICAL WHERE SHOWN)
OPTIONAL BYPASS DUCT
NOTE:
1. This damper not required unless optional by pass duct is installed.
ADJUSTABLE MECHANISM
FLUE GAS DUCT
STACK
1st STAGE VENTURI SCRUBBER
POWERHOUSE
2nd STAGE VENTURI SCRUBBER
118 FT. (APPROX.)
STEAM REHEATER (See Note 1)
ENTRAINMENT SEPARATORS
I.D. FAN
AIR PREHEATER
RECYCLE PUMPS
OPTIONAL BYPASS DUCT
EXPANSION JOINT (TYPICAL WHERE SHOWN)
177 FT. (APPROX.)

Figure B-11. Two-Stage Venturi Scrubber System—Plan and Elevation—New Unit

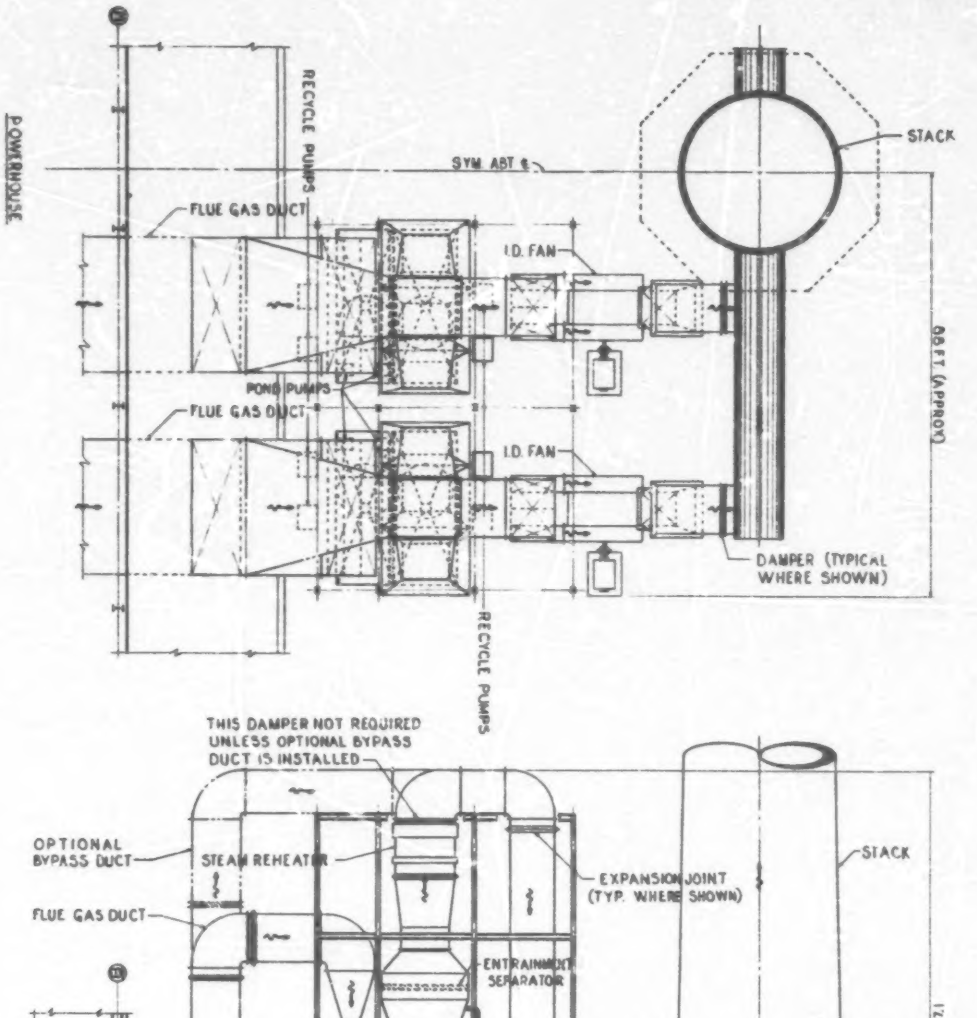

POWERHOUSE
RECYCLE PUMPS
SYM ABT ℄
STACK
FLUE GAS DUCT
I.D. FAN
88 FT (APPROX)
POND PUMPS
FLUE GAS DUCT
I.D. FAN
DAMPER (TYPICAL WHERE SHOWN)
RECYCLE PUMPS
THIS DAMPER NOT REQUIRED UNLESS OPTIONAL BYPASS DUCT IS INSTALLED
OPTIONAL BYPASS DUCT
STEAM REHEATER
EXPANSION JOINT (TYP. WHERE SHOWN)
STACK
FLUE GAS DUCT
ENTRAINMENT SEPARATOR
129 FT (APPROX)
POWERHOUSE
PARTICULATE VENTURI
MOBILE BED ABSORBER
SUMP
ENTRAINMENT SEPARATOR
AGITATORS
I.D. FAN
AIR PREHEATER
PUMP
PUMP
RECIRCULATING TANKS
133 FT. (APPROX)

Figure B-12. Venturi-Mobile Bed Scrubber System—Plan and Elevation—New Unit

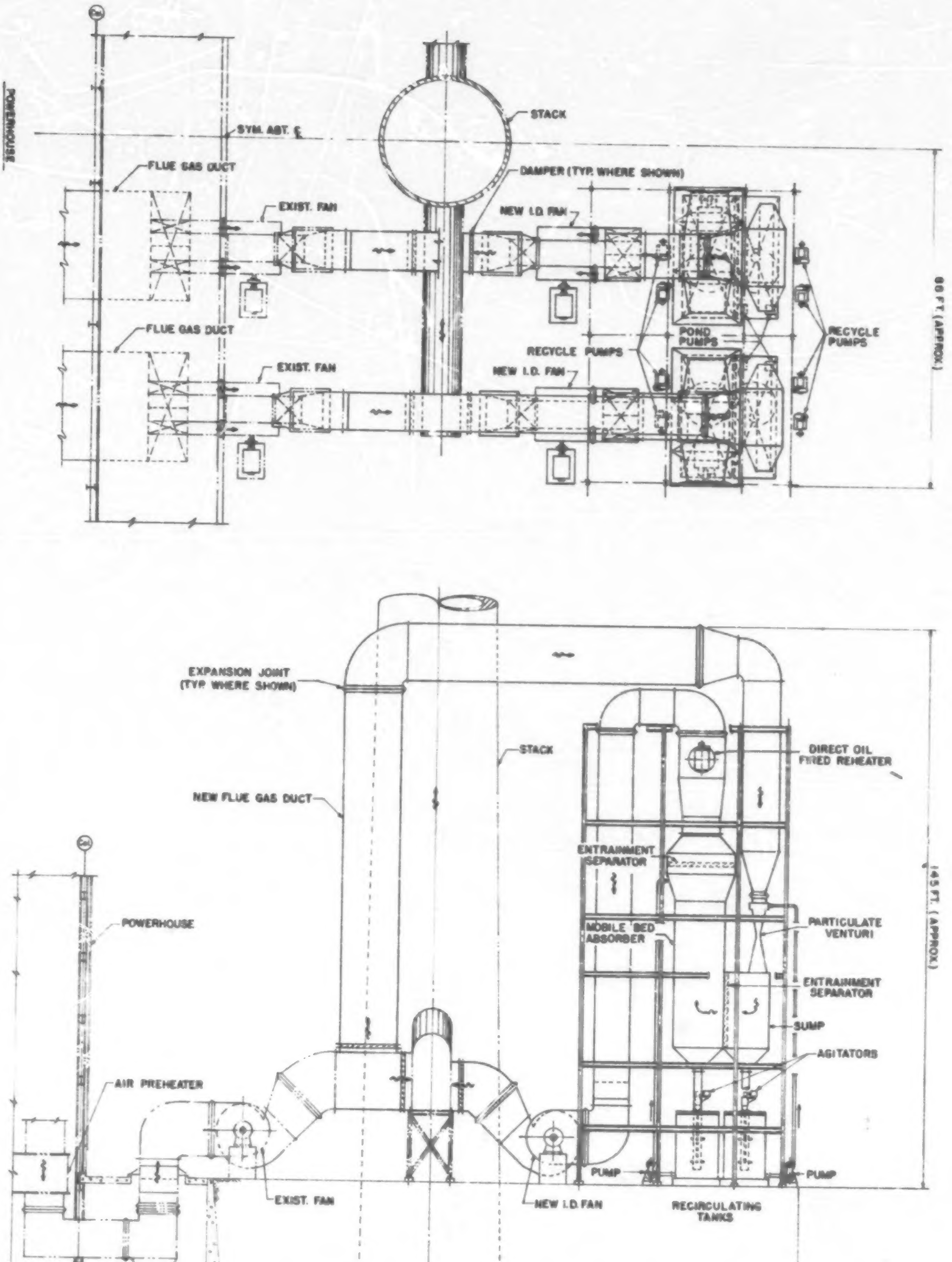

POWERHOUSE
SYM. ABT. ℄
STACK
FLUE GAS DUCT
DAMPER (TYP. WHERE SHOWN)
EXIST. FAN
NEW I.D. FAN
FLUE GAS DUCT
EXIST. FAN
NEW I.D. FAN
RECYCLE PUMPS
POND PUMPS
RECYCLE PUMPS
86 FT. (APPROX.)
EXPANSION JOINT (TYP WHERE SHOWN)
STACK
NEW FLUE GAS DUCT
DIRECT OIL FIRED REHEATER
ENTRAINMENT SEPARATOR
POWERHOUSE
MOBILE BED ABSORBER
PARTICULATE VENTURI
ENTRAINMENT SEPARATOR
SUMP
AGITATORS
145 FT. (APPROX.)
AIR PREHEATER
PUMP
PUMP
EXIST. FAN
NEW I.D. FAN
RECIRCULATING TANKS
186 FT. (APPROX.)

Figure B-13. Venturi-Mobile Bed Scrubber System–Plan and Elevation–Existing Unit

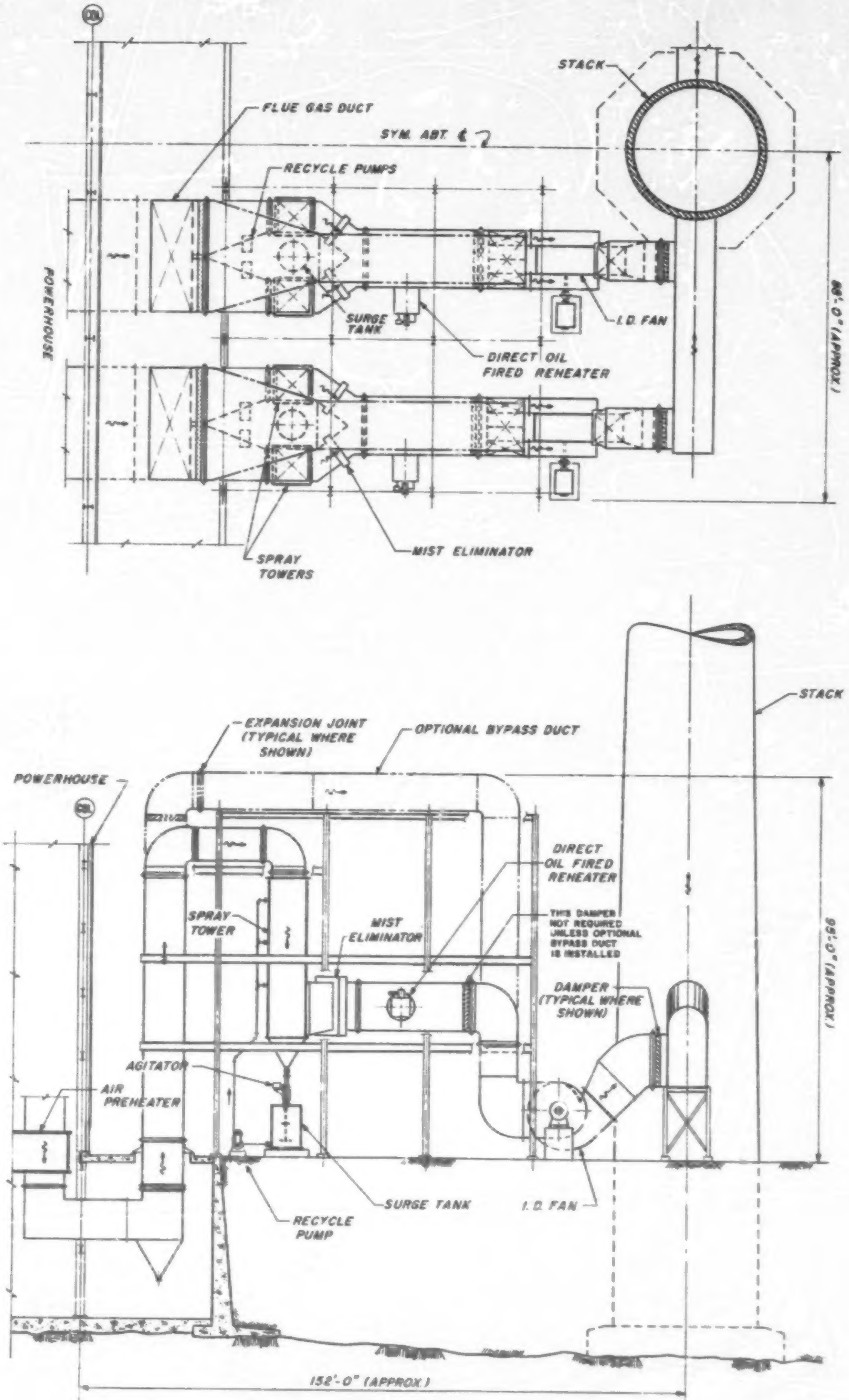

STACK
FLUE GAS DUCT
SYM. ABT. ℄
RECYCLE PUMPS
POWERHOUSE
SURGE TANK
I.D. FAN
DIRECT OIL FIRED REHEATER
80'-0" (APPROX.)
SPRAY TOWERS
MIST ELIMINATOR
STACK
EXPANSION JOINT (TYPICAL WHERE SHOWN)
OPTIONAL BYPASS DUCT
POWERHOUSE
DIRECT OIL FIRED REHEATER
SPRAY TOWER
MIST ELIMINATOR
THIS DAMPER NOT REQUIRED UNLESS OPTIONAL BYPASS DUCT IS INSTALLED
DAMPER (TYPICAL WHERE SHOWN)
95'-0" (APPROX.)
AGITATOR
AIR PREHEATER
SURGE TANK
I.D. FAN
RECYCLE PUMP
152'-0" (APPROX.)

Figure B-14. Spray Tower–Plan and Elevation–New Unit

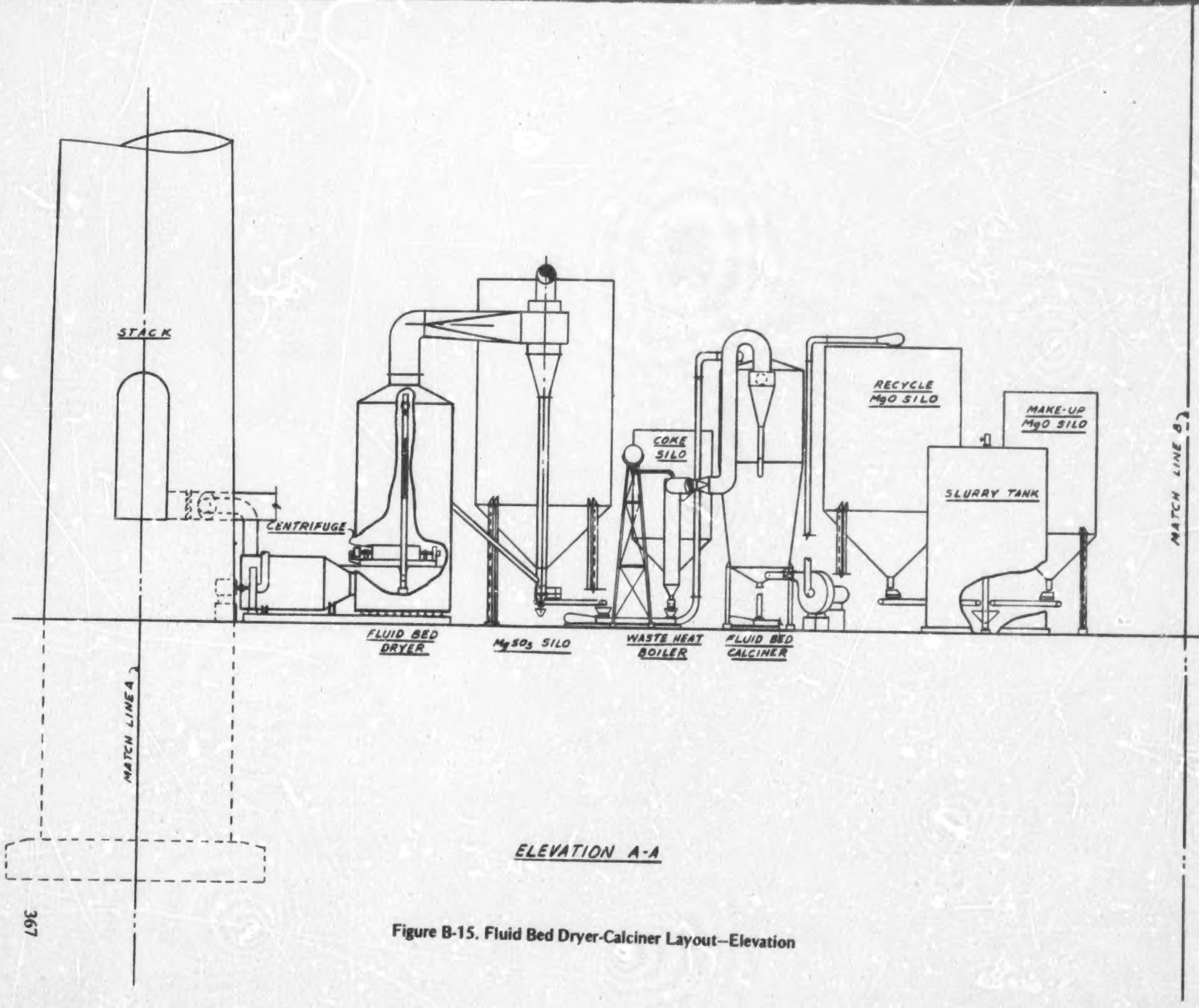

STACK
CENTRIFUGE
FLUID BED DRYER
MgSO3 SILO
COKE SILO
WASTE HEAT BOILER
FLUID BED CALCINER
RECYCLE MgO SILO
MAKE-UP MgO SILO
SLURRY TANK
MATCH LINE A
MATCH LINE B
ELEVATION A-A

Figure B-15. Fluid Bed Dryer-Calciner Layout–Elevation

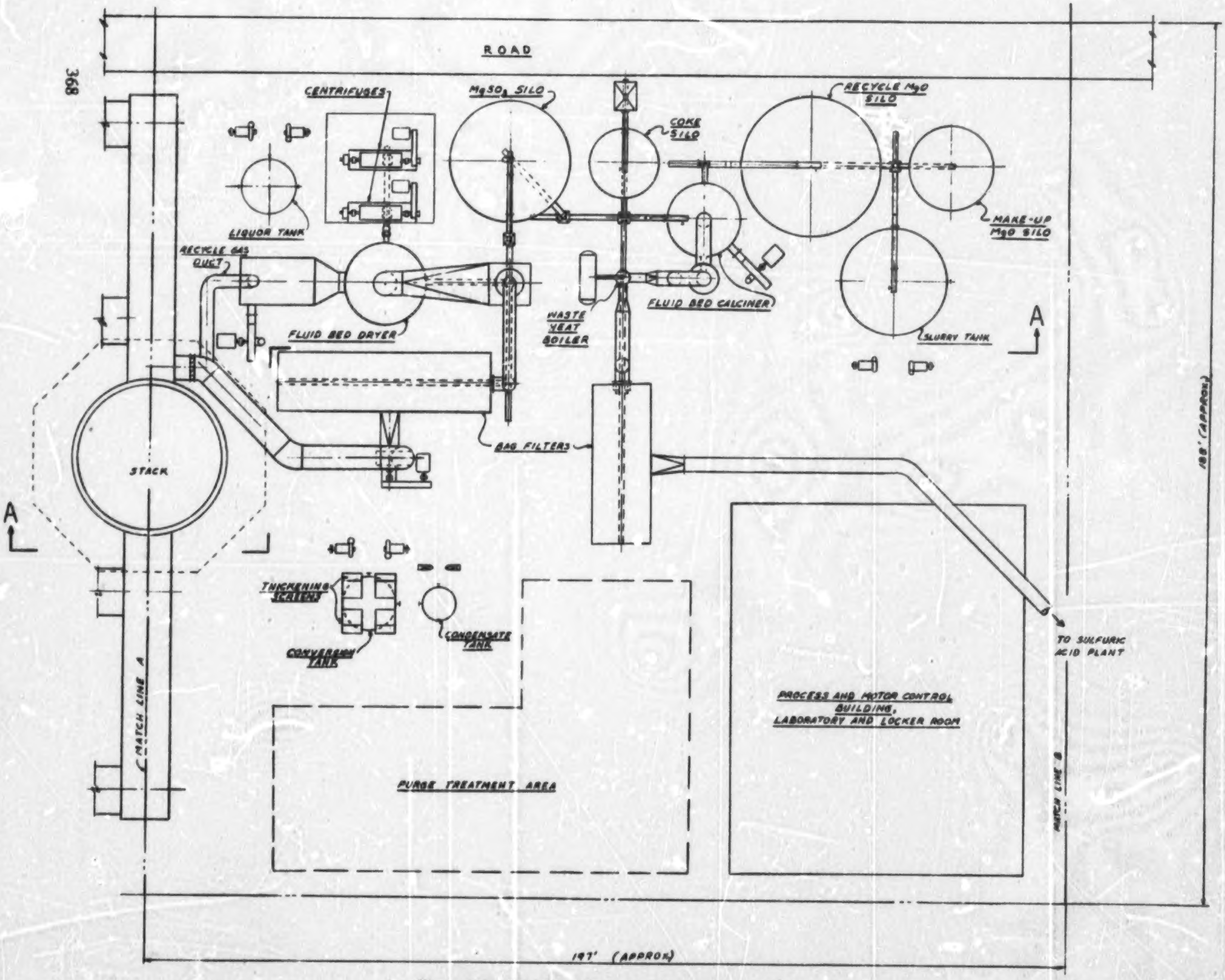

ROAD
CENTRIFUGES
MgSO4 SILO
COKE SILO
RECYCLE MgO SILO
MAKE-UP MgO SILO
LIQUOR TANK
RECYCLE GAS DUCT
FLUID BED DRYER
WASTE HEAT BOILER
FLUID BED CALCINER
SLURRY TANK
A
A
BAG FILTERS
STACK
THICKENING SCREENS
CONVERSION TANK
CONDENSATE TANK
TO SULFURIC ACID PLANT
PROCESS AND MOTOR CONTROL BUILDING, LABORATORY AND LOCKER ROOM
PURGE TREATMENT AREA
MATCH LINE A
MATCH LINE B
188' (APPROX)
197' (APPROX)

Figure B-16. Fluid Bed Dryer-Calciner Layout–Plan

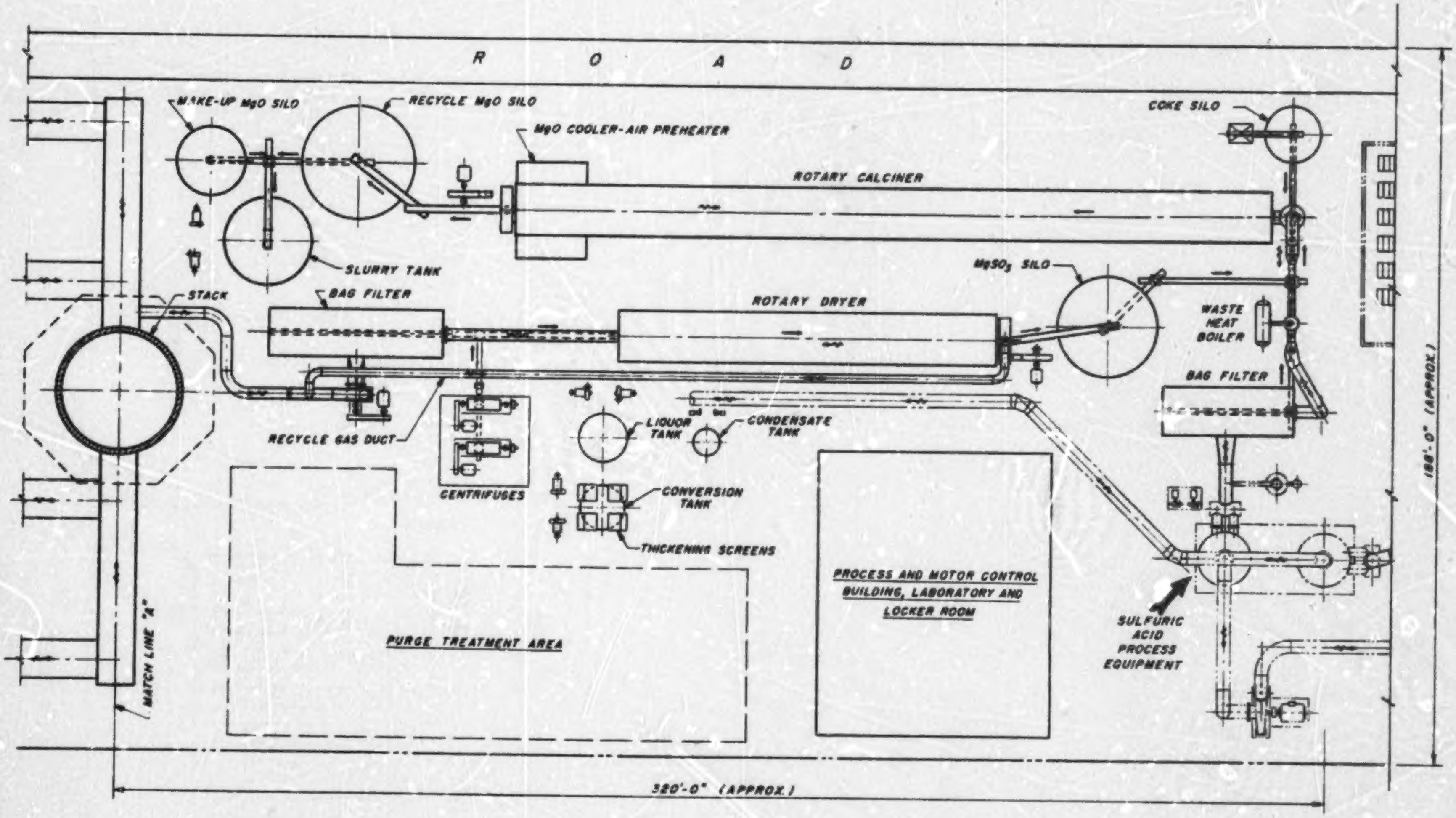

R O A D
MAKE-UP MgO SILO
RECYCLE MgO SILO
MgO COOLER-AIR PREHEATER
COKE SILO
ROTARY CALCINER
SLURRY TANK
MgSO3 SILO
STACK
BAG FILTER
ROTARY DRYER
WASTE HEAT BOILER
BAG FILTER
RECYCLE GAS DUCT
LIQUOR TANK
CONDENSATE TANK
CENTRIFUGES
CONVERSION TANK
THICKENING SCREENS
PROCESS AND MOTOR CONTROL BUILDING, LABORATORY AND LOCKER ROOM
SULFURIC ACID PROCESS EQUIPMENT
PURGE TREATMENT AREA
MATCH LINE "A"
188'-0" (APPROX.)
320'-0" (APPROX.)

Figure B-17. Rotary Dryer and Calciner Layout–Plan

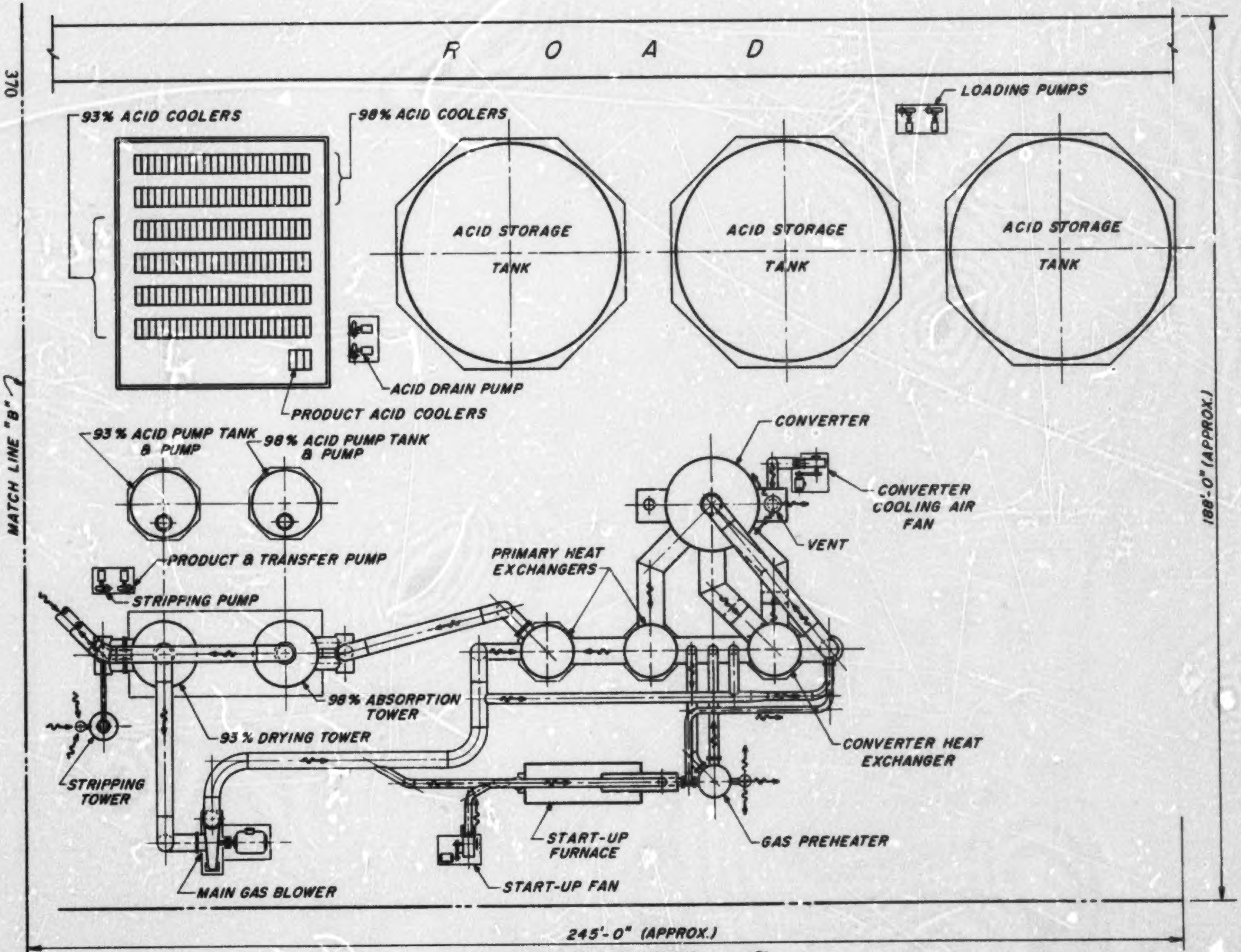

R O A D
LOADING PUMPS
93% ACID COOLERS
98% ACID COOLERS
ACID STORAGE TANK
ACID STORAGE TANK
ACID STORAGE TANK
ACID DRAIN PUMP
PRODUCT ACID COOLERS
93% ACID PUMP TANK & PUMP
98% ACID PUMP TANK & PUMP
CONVERTER
CONVERTER COOLING AIR FAN
VENT
PRIMARY HEAT EXCHANGERS
PRODUCT & TRANSFER PUMP
STRIPPING PUMP
98% ABSORPTION TOWER
93% DRYING TOWER
STRIPPING TOWER
CONVERTER HEAT EXCHANGER
START-UP FURNACE
GAS PREHEATER
MAIN GAS BLOWER
START-UP FAN
MATCH LINE "B"
245'-0" (APPROX.)
188'-0" (APPROX.)

Figure B-18. Sulfuric Acid Unit Layout—Plan

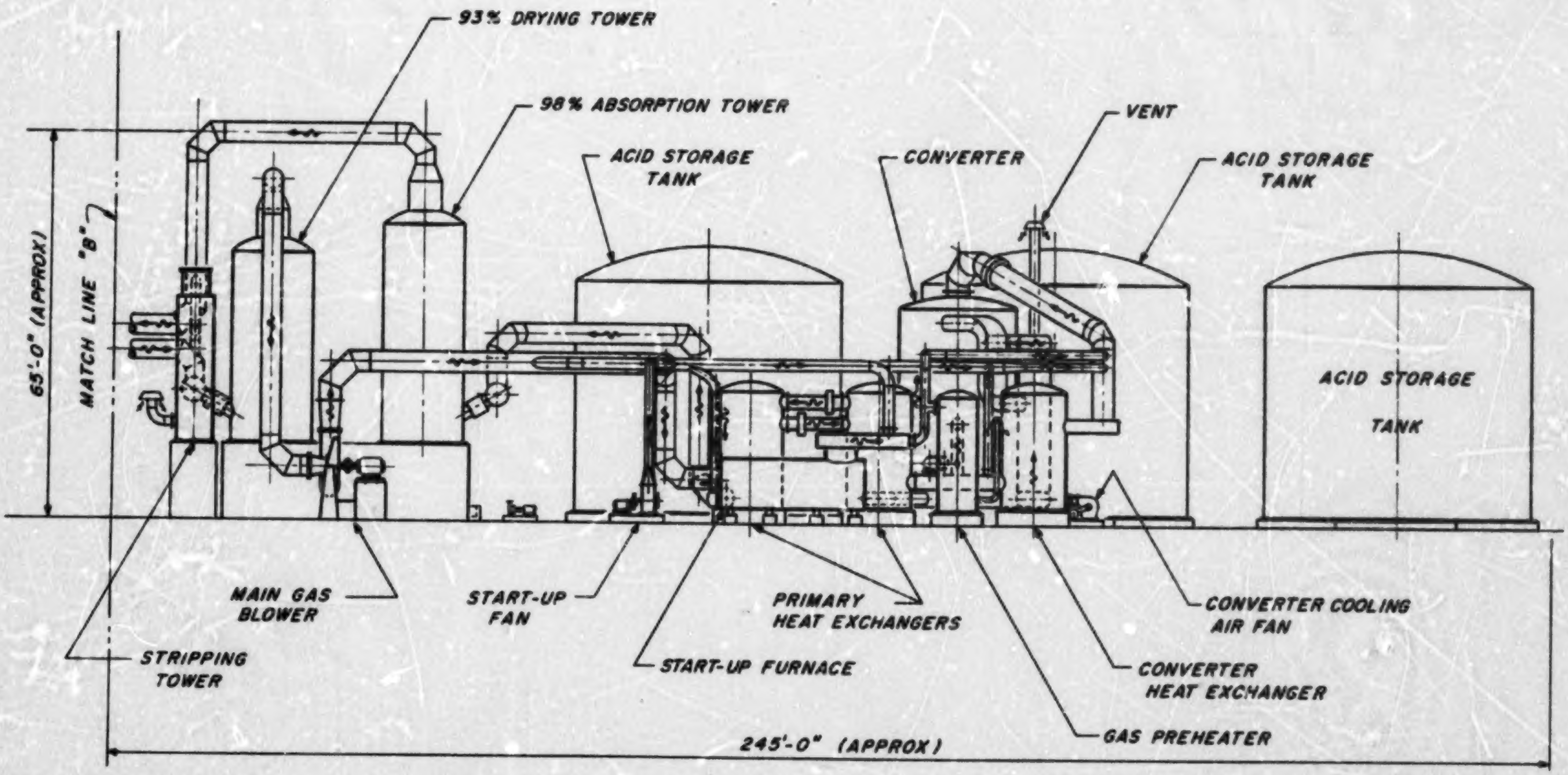

93% DRYING TOWER
98% ABSORPTION TOWER
ACID STORAGE TANK
CONVERTER
VENT
ACID STORAGE TANK
ACID STORAGE TANK
65'-0" (APPROX)
MATCH LINE "B"
MAIN GAS BLOWER
START-UP FAN
PRIMARY HEAT EXCHANGERS
CONVERTER COOLING AIR FAN
STRIPPING TOWER
START-UP FURNACE
CONVERTER HEAT EXCHANGER
GAS PREHEATER
245'-0" (APPROX)

Figure B-19. Sulfuric Acid Unit Layout–Elevation